BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Horizon West Transmission, LLC (U222-E) for a Certificate of Public Convenience and Necessity for the Ironwood Transmission Line Project.

A.25-09-_____

(Filed September 22, 2025)

APPLICATION OF HORIZON WEST TRANSMISSION, LLC (U222-E) FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE IRONWOOD TRANSMISSION LINE PROJECT

(EXHIBITS 4, 6, AND 13 REDACTED)

(EXHIBIT 17 FILED VIA ARCHIVAL GRADE DVD)

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September 22, 2025

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Pursuant to the California Public Utilities Code ("PU Code"), California Public Utilities Commission ("Commission" or "CPUC") General Order ("GO") 131-E, and the Commission's Rules of Practice and Procedure ("Rules"), Horizon West Transmission, LLC ("Horizon West") (U222-E) submits this application requesting a certificate of public convenience and necessity ("CPCN") for the Ironwood Transmission Line Project (the "Ironwood Project") ("Application").

I. INTRODUCTION

The Ironwood Project is an approximately 86-mile 500 kilovolt ("kV") transmission line that will connect the Imperial Valley Substation, which is owned and operated by San Diego Gas & Electric Company ("SDG&E"), to the North Gila Substation in Yuma, Arizona, which is owned and operated by Arizona Public Service Company ("APS"). The North Gila Substation is outside the California Independent System Operator Corporation ("CAISO") region and located in the WestConnect planning region.[1]

The Ironwood Project is a policy-driven upgrade to the transmission system that was identified and selected by the CAISO in its 2022-2023 Transmission Plan, approved by the CAISO

1 In various CAISO materials, the Ironwood Project is referred to as the North Gila-Imperial Valley #2 500 kV Transmission Line Project.

Board of Governors ("Board") and issued May 22, 2023 ("2022-2023 Transmission Plan").[2] The 2022-2023 Transmission Plan identified a policy-driven need for the Ironwood Project as part of the Southern Area Reinforcement Projects in southern California.[3]

The CAISO Board-approved need evaluation for the Ironwood Project is included with this Application in Exhibit 1. There has been no substantial change to the scope, estimated cost, or timeline of the Ironwood Project from that approved by the CAISO Board. The Ironwood Project thus qualifies for the rebuttable presumption of need that applies pursuant to PU Code Section 1001.1 and GO 131-E.

As a policy-driven upgrade, the Ironwood Project was selected through a competitive solicitation conducted by CAISO in accordance with Section 24.5 of the CAISO Tariff. After evaluating competing bids, the CAISO selected Horizon West as the approved project sponsor, and explained its selection criteria and decision in a report dated April 11, 2024 ("Project Sponsor Selection Report").[4] Once constructed, the Ironwood Project will become part of the CAISO-controlled transmission system. In accordance with the CAISO's requirements, Horizon West has executed an Approved Project Sponsor Agreement with the CAISO,[5] and will finance, develop, construct, own, operate, and maintain the Ironwood Project as a Participating Transmission Owner ("PTO") in accordance with the CAISO Tariff. The costs of the Ironwood

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2 The 2022-2023 Transmission Plan is attached as Exhibit 1.

3 Exhibit 1 (2022-2023 Transmission Plan) at 99-100. The Southern Area Reinforcement Projects are intended to address the East of Miguel, Bay Boulevard-Silvergate, Encina-San Luis Rey, Sycamore area, San Luis Rey-San Onofre, and Silvergate-Old Town constraints identified in the Commission's base and sensitivity portfolios. *Id*. at 98.

4 North Gila-Imperial Valley #2 500 kV Line Project, Project Sponsor Selection Report (April 11, 2024), attached as Exhibit 3.

5 Approved Project Sponsor Agreement (APSA) between Horizon West Transmission, LLC and California Independent System Operator Corporation, North Gila-Imperial Valley #2 kV Line Project (Dec. 29, 2024), attached as Exhibits 4 (Public Version) and 4C (Confidential Version).

Project will be recovered solely through transmission rates as part of the CAISO's Transmission Access Charge ("TAC"), following approval by the Federal Energy Regulatory Commission ("FERC") pursuant to FERC's exclusive jurisdiction over rates for interstate transmission service.

Horizon West seeks a CPCN to construct the Ironwood Project and meet its obligations under the Approved Project Sponsor Agreement. Horizon West intends to utilize resources and facilities within the NextEra Energy, Inc. ("NextEra Energy") corporate organization pursuant to agreements with certain affiliates to facilitate the efficient and cost-effective development, construction, ownership, operation, and maintenance of the Ironwood Project. To enable this contracted use of shared resources, Horizon West requests that the Commission grant exemptions from certain affiliate transaction rules. The requested exemptions and the grounds supporting approval are set forth in Section VIII of this Application.

Horizon West requests that the Commission grant Horizon West a CPCN authorizing construction of the Ironwood Project as described in this Application and the supporting documentation and certify an appropriate environmental document under the California Environmental Quality Act ("CEQA"). Horizon West respectfully requests a decision by September 2028 to allow Horizon West to complete construction and energize the Ironwood Project by December 31, 2030 in advance of the agreed-upon energization date with the CAISO of December 31, 2031. Horizon West seeks to complete the Ironwood Project in advance of the required in-service date because the Ironwood Project is needed as soon as possible to deliver existing energy generated in Arizona and New Mexico into southern California. A proposed schedule for the proceeding is provided in Section VII.D below.

II. SUPPORTING DOCUMENTS

In support of Horizon West's request for a CPCN for the Ironwood Project, this Application includes the following Exhibits 1-17 (appended hereto):

Exhibit 1: CAISO Board-Approved 2022-2023 Transmission Plan (May 22, 2023) and CAISO Board Voting Meeting Results

Exhibit 2: CAISO Description and Functional Specifications for the North Gila-Imperial Valley #2 500 kV Line Project (August 21, 2023)

Exhibit 3: CAISO North Gila-Imperial Valley #2 500 kV Line Project, Project Sponsor Selection Report (April 11, 2024)

Exhibit 4: CAISO-Horizon West Approved Project Sponsor Agreement for the Ironwood Project (December 24, 2024) (Public Version), and Exhibit 4C (Confidential Version)

Exhibit 5: Project Map

Exhibit 6: Project Cost Estimate (Public Version), and Exhibit 6C (Confidential Version)

Exhibit 7: Project Implementation Plan

Exhibit 8: Horizon West Financial Statement

Exhibit 9: NextEra Energy, Inc. Proxy Statement

Exhibit 10: Electric and Magnetic Fields Management Plan

Exhibit 11: List of Required Permits

Exhibit 12: Governmental Agency Consultations

Exhibit 13: Annual Revenue Requirement (Public Version), and Exhibit 13C (Confidential Version)

Exhibit 14: Notice of Application for a Certificate of Public Convenience and Necessity

Exhibit 15: NextEra Energy Affiliates' Shared Officers and Responsibilities

Exhibit 16: Compliance with the Commission's Environmental and Social Justice ("ESJ") Action Plan

Exhibit 17: Proponent's Environmental Assessment (Filed Via Archival Grade DVD)

III. PROJECT OVERVIEW

A. Project Description

The Ironwood Project is an approximately 86-mile, 500 kV transmission line that will extend from APS's North Gila Substation to SDG&E's Imperial Valley Substation. The Ironwood Project will be located in western Yuma County, Arizona and Imperial County, California, crossing predominantly unincorporated lands as well as federal, state, municipal, and private land. These lands include unincorporated areas of Imperial and Yuma counties, the city of Calexico, California, and public lands under the jurisdiction or management of the U.S. Bureau of Land Management ("BLM"), U.S. Bureau of Reclamation ("USBR"), and the California Department of Parks and Recreation.

The Ironwood Project is needed to mitigate resource deliverability constraints identified in the CAISO's 2022-2023 Transmission Plan and will enable delivery of existing, low-cost generation in the resource portfolios approved by the Commission. The Ironwood Project is part of a portfolio of projects that the CAISO identified as needed to meet major constraints across the Southern California Edison Company ("SCE") Metro, SCE Eastern, and SDG&E areas. The Ironwood Project will supplement the existing SDG&E 500 kV transmission line (known as the Southwest Powerlink) between the North Gila and Imperial Valley substations, greatly increasing transfer capability in the region. The Ironwood Project is expected to be operating by the end of 2030.

Based on current design, Horizon West anticipates that approximately 300 new transmission structures will be installed for the Ironwood Project. Structures will span 1,200 to 1,600 feet (3 to 4 structures per mile), with a typical right-of-way ("ROW") of 250 feet. Structures will be installed on concrete foundations. Specific structure and foundation types and quantities are described in Chapter 3 of the Proponent's Environmental Assessment, attached as Exhibit 17

("PEA"). The locations for each structure type will be determined during final design, and selected based on site-specific conditions (*e.g.*, topography, terrain, constrained ROW, or other engineering requirements) or to mitigate potential impacts.

Three conductors per phase (triple bundle) will be installed for the 86-mile alignment, for a total of nine conductors between the three phases. The design includes approximately 86 miles of overhead ground wire ("OHGW"), one in each overhead shielding position, and at least one of the OHGW will include optical ground wire ("OPGW"). The minimum conductor height above ground for the transmission line will be 30 to 40 feet, at the maximum operating temperature, based on the National Electrical Safety Code, the Commission's GO 95 requirements, the Horizon West Wildfire Mitigation Plan, and Horizon West's design standards. To protect conductors from lightning strikes, two overhead wires will be installed on the top of the structures. Insulators, made of an extremely low conducting material such as porcelain, glass, or polymer, will be used to suspend the conductors from each structure. Anticipated design of conductors and overhead wires is detailed in Chapter 3 of the PEA.

B. The CAISO-Identified Policy Need for the Ironwood Project

The Ironwood Project will increase the capacity of the North Gila and Imperial Valley substations and, therefore, the existing utility system. The Ironwood Project is a policy-driven upgrade to the transmission system that was identified and selected by the CAISO in its 2022-2023 Transmission Plan approved by the CAISO Board of Governors. The 2022-2023 Transmission Plan identified a policy-driven need for the Ironwood Project as part of the Southern Area Reinforcement Projects in southern California, to mitigate resource deliverability constraints and to meet generation requirements established in the CPUC-developed generation portfolios.[6]

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[6] Exhibit 1 (2022-2023 Transmission Plan) at 99-100. The Southern Area Reinforcement Projects are

The CAISO approved the Ironwood Project as necessary to help mitigate the East of Miguel deliverability constraint. The East of Miguel Constraint results in over 3,000 MW of undeliverable resources in the Commission's base case resource portfolio, and over 10,000 MW of undeliverable resources in the Commission's sensitivity case portfolio.[7] The East of Miguel Constraint includes transmission system limitations from thermal overloads under contingency cases in a variety of facilities. In the base portfolio case, overloads were identified on the Suncrest-Sycamore 230 kV #1 and #2 lines and the Miguel Substation 500/230 kV Bank 80 and Bank 81. Under the sensitivity case, overloads were also identified on the ECO-Miguel 500 kV line, as well as additional contingency triggers for overloads on the Suncrest-Sycamore 230 kV #1 and #2 lines and the Miguel Substation 500/230 kV Bank 80 and Bank 81. The Ironwood Project supports mitigation of the East of Miguel Constraint by connecting the existing North Gila and Imperial Valley substations with a new 500 kV circuit.

The CAISO Board approved the 2022-2023 Transmission Plan, including the Ironwood Project, on May 18, 2023. The Board-approved 2022-2023 Transmission Plan explicitly identifies the Ironwood Project as a new policy-driven transmission project "found to be needed."[8] The CAISO evaluated six different alternatives to address the major constraints identified in the SCE Metro, SCE Eastern, and SDG&E areas. The CAISO selected alternative A2, which includes the Ironwood Project, because it "has a lower estimated cost, so it is the preferred alternative."[9]

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intended to address the East of Miguel, Bay Boulevard-Silvergate, Encina-San Luis Rey, Sycamore area, San Luis Rey-San Onofre, and Silvergate-Old Town constraints identified in the base and sensitivity portfolios. *Id*. at 98.

7 *Id.* at 96-97 (Table 3.5-30).

8 *Id.* at 169 (Table 8.2-2).

9 *Id.* at F-148 (Appendix F).

C. CAISO Competitive Solicitation

The CAISO's transmission planning process includes a competitive solicitation process for new, stand-alone regional transmission facilities needed for reliability, economic, and/or policy-driven reasons.[10] The 2022-2023 Transmission Plan included the Ironwood Project in the list of transmission elements that are eligible for competitive solicitation under the CAISO Tariff.[11] The 2022-2023 Transmission Plan included as an Appendix CAISO's Functional Specifications for the Ironwood Project ("CAISO Functional Specifications"), provided as Exhibit 2 to this Application.[12] The CAISO requested competitive bids and opened the bid window on June 26, 2023. The CAISO provided prospective project sponsors the opportunity to submit proposals to finance, develop, construct, own, operate, and maintain a project meeting the CAISO Functional Specifications. In accordance with CAISO Tariff Section 24.5.1 and the schedule for the 2022-2023 Transmission Plan projects eligible for competitive solicitation, the CAISO's bid solicitation window for the project remained open through September 29, 2023.

Horizon West submitted its project sponsor application for the Ironwood Project on September 29, 2023, as did four other applicants. Collectively, the five bidders submitted six proposals.[13] The CAISO determined that all bidders were qualified and validated all six of the

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10 *Id.* at 171; CAISO Tariff § 24.5.

11 Exhibit 1 (2022-2023 Transmission Plan) at 171.

12 Description and Functional Specifications for Transmission Facilities Eligible for Competitive Solicitation, Appendix I to the CAISO 2022-2023 Transmission Plan (Aug. 21, 2023), attached hereto as Exhibit 2. Per CAISO, after the Board approved the 2022-2023 Transmission Plan CAISO determined certain revisions were necessary and issued an updated Appendix I on August 21, 2023; *see* https://www.caiso.com/Documents/2022-2023-transmission-planning-process-competitive-solicitation-project-specification-revisions-posted.html.

13 Exhibit 3 (Project Sponsor Selection Report) at 3.

proposals.[14] The CAISO analyzed the proposals pursuant to the process set forth in CAISO Tariff Section 24.5 utilizing a number of selection criteria.[15]

Based on its comparative evaluation, the CAISO determined that "Horizon West proposed the lowest estimated capital costs, significant cost containment measures, and the fewest proposed cost cap exclusions, which produced the lowest anticipated projected total revenue requirements at the lowest evaluated risk to [CA]ISO ratepayers."[16] In evaluating the key selection criteria, the CAISO determined that Horizon West:

- Had one of the two strongest proposals in terms of experience in acquiring right-of-way to facilitate project approval and construction because of Horizon West's experience acquiring land rights in California;[17]
- Demonstrated its ability to complete projects in a timely manner;[18]
- Has "substantial financing experience, financial resources, and financial backing sufficient to finance this project along with any other project for which it might be selected as the approved project sponsor;"[19] and
- Has an environmental permitting team with "as much or more relevant experience" as any other bidder, and "demonstrated that it and its team have sufficient experience with the design and engineering of [Extra-High-Voltage] transmission projects to ensure that they are fully capable of performing the design and engineering of this project."[20]

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14 *Id.* at 4, 6.

15 *Id.* at 3. The CAISO's key selection criteria for this project included: (1) the Project Sponsor's existing rights of way and substations; (2) the experience of the Project Sponsor and its team in acquiring rights of way; (3) the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet that schedule; (4) the financial resources of the Project Sponsor and its team; (5) the technical and engineering qualifications and experience of the Project Sponsor and its team; and (6) demonstrated cost containment capability of the Project Sponsor and its team, specifically, binding cost control measures, including any binding agreements to accept a cost cap that would preclude costs for the transmission solution above the cap from being recovered through the CAISO TAC.

16 *Id.* at 130.

17 *Ibid.*

18 *Ibid.*

19 *Ibid.*.

20 *Id.* at 130-31.

Regarding the CAISO's non-key selection criteria, the CAISO determined that "Horizon West's proposal was either as strong as or better than the proposals of the other project sponsors for every selection factor."[21]

For these reasons, the CAISO selected Horizon West as the approved project sponsor, finding that "Horizon West and its team are qualified, experienced, and have the financial resources to capably, cost-effectively, and reliably license, finance, construct, operate, and maintain this particular project at the lowest cost and by the specified in-service date."[22] The CAISO and Horizon West have executed an Approved Project Sponsor Agreement, which is attached as Exhibit 4 (Public) and Exhibit 4C (Confidential). As the approved project sponsor and pursuant to this Approved Project Sponsor Agreement, Horizon West will be responsible for design, procurement, installation, and commissioning of the selected system.

D. Project Objectives

Consistent with the foregoing, the key objectives of the Ironwood Project are to:

- Meet the CAISO's policy-driven need for the Ironwood Project to support mitigation of the East of Miguel deliverability constraint,[23] which the CAISO found presently results in zero deliverability for resources in the Commission's base portfolio (3,080 MW) and sensitivity portfolio (10,398 MW) by connecting the existing North Gila and Imperial Valley substations with a new 500 kV circuit (CAISO 2022-2023 Transmission Plan).
- As part of the Southern Area Reinforcement, support the cost-effective, common upgrade mitigation of identified transmission constraints on the Devers-Red Bluff 500 kV, East of Miguel, Bay Boulevard-Silvergate, Encina-San Luis Rey, Sycamore area, San Luis Rey-San Onofre, and Silvergate-Old Town lines by connecting the existing North Gila and Imperial Valley substations with a new 500 kV circuit.

[21] *Id.* at 131.

[22] *Ibid.*

[23] As described in CAISO's 2022-2023 Transmission Plan, deliverability of portfolio resources east of the existing SDG&E Miguel Substation is limited by thermal overloading of existing lines and transformers (referred to as the "East of Miguel Constraint").

- Meet the CAISO's functional specifications for the Ironwood Project as set forth in Appendix I of the 2022-2023 Transmission Plan.

- Achieve commercial operation by December 2030 to provide critical deliverability access to generation resources in California, Arizona, and New Mexico.

- Design, construct, and operate the Ironwood Project to minimize potential wildfire and other hazards, with public safety and well-being as a top priority, consistent with Horizon West's approved Wildfire Mitigation Plan.

- Meet the need for the Ironwood Project in a safe, cost-effective manner consistent with Horizon West's Approved Project Sponsor Agreement to minimize cost impacts to customers.

- Minimize disturbance to local communities by siting the project adjacent to existing utilities, avoiding residential areas as much as possible.

- Avoid, minimize, or mitigate potential impacts to sensitive environmental resources and areas.

- Design, construct, and operate the project in conformance with Horizon West's standards, the National Electric Safety Code, and other applicable federal and state codes and regulations.

E. The Ironwood Project Qualifies for the Rebuttable Presumption of Need Pursuant to PU Code Section 1001.1

PU Code Section 1001.1 states that in a CPCN proceeding 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 the following four criteria are met:

(a) The Independent System Operator 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 Independent System Operator is a party to the proceeding.

(c) The Independent System Operator 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 Independent System Operator governing board. (PU Code § 1001.1.)

The Ironwood Project qualifies for this rebuttable presumption of need, meeting each of the approval criteria. As described in Section III.B, the CAISO Board approved the Ironwood Project as part of the 2022-2023 Transmission Plan as a policy-driven transmission project that is needed to help mitigate the East of Miguel deliverability constraint and enable delivery of 3,000 to 10,000 MW of energy into Southern California. The CAISO approved the Ironwood Project as a needed policy-driven project in the 2022-2023 Transmission Plan because it "has a lower estimated cost, so it is the preferred alternative."[24] Thus, as required by PU Code 1001.1, the CAISO 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." (PU Code § 1001.1(a).) As to the second criterion, Horizon West understands that the CAISO will seek party status in this proceeding. (PU Code § 1001.1(b).)

The third criterion is satisfied because the CAISO Board-approved need evaluation is included in the 2022-2023 Transmission Plan, attached to this Application as Exhibit 1. The Ironwood Project is identified as a policy-driven transmission project that is needed in Table 8.2-2 at page 169. (PU Code § 1001.1(c).) Further, the final criterion is met because there have been no substantial changes to the scope, estimated cost, or timeline of the Ironwood Project, as proposed in this Application compared to the project approved by CAISO. (PU Code § 1001.1(d).)

IV. GO 131-E REQUIREMENTS

The Ironwood Project requires a CPCN pursuant to GO 131-E, Section III.A.1.c. The following sections include the information required by GO 131-E, Section VII, applicable to transmission line facilities over 200 kV.

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24 Exhibit 1 (2022-2023 Transmission Plan) at F-148 (Appendix F).

A. <u>Pre-Filing Requirements</u>

Horizon West has satisfied the requirements of GO 131-E, Section VII.A.1 with respect to the Ironwood Project. This Application is filed not less than 12 months prior to the date of a required decision. (GO 131-E, Section VII.A.1.a.) Consistent with the proposed schedule set forth in Section VII.D, Horizon West requests a Commission decision in September 2028, well over 12 months after the date this Application is filed.

Horizon West initiated pre-filing consultation with Energy Division staff on or around September 4, 2024. This satisfied the requirements of GO 131-E to provide written notice to Energy Division staff not less than 12 months prior to filing this Application, and to initiate pre-filing consultation with Energy Division staff pursuant to Rule 2.4 not less than six months prior to filing this Application. (GO 131-E, Sections VII.A.1.b and c.)

B. <u>Detailed Description of the Proposed Transmission Line, Routes, and Equipment (Section VII.A.2.a)</u>

As part of the Ironwood Project, Horizon West proposes to install new transmission towers, poles, foundations, conductors, insulators and associated hardware, and OHGW, including OPGW. No existing facilities will be modified, and no substations, switching stations, gas storage facilities, gas pipelines, or service buildings will be installed as part of the Ironwood Project. A detailed description of the proposed transmission facilities, including proposed transmission equipment, is included in Chapter 3 of the PEA. A detailed discussion of the proposed transmission line route, alternative routes considered, and the method by which they were analyzed and compared, are discussed in detail in Chapter 6 of the PEA and in the Ironwood Transmission Line Project Routing Study, included as Appendix K to the PEA ("<u>Routing Study</u>"). A proposed schedule for certification, construction, and commencement of operation of the Ironwood Project is included in <u>Exhibit 7</u> (Project Implementation Plan).

C. Map of the Project (Section VII.A.2.b)

Locations of the Ironwood Project's alignment, which generally includes the locations where work will occur, are illustrated in the map provided in Exhibit 5 (Project Map), and in PEA Figure 3-1 (Proposed Project Overview Map) and PEA Appendix A (Detailed Maps and Design Drawings).

Maps and aerial photographs showing populated areas, parks, recreational areas, scenic areas, and land uses in the vicinity of the Ironwood Project alignment are provided in PEA Chapter 5.1 (Aesthetics), Figure 5.2-2 (Agricultural Use Zoning within 0.5 Mile of the Proposed Project), Figure 5.11-1 (General Plan Land Use Designations within 0.5 Mile of the Proposed Project Area), Figure 5.11-2 (Zoning Designations within 0.5 Mile of the Proposed Project Area), Figure 5.11-4 (Land Ownership within 0.5 Mile of the Project Study Area), Figure 5.15-1 (Public Services Near the Proposed Project), and Figure 5.16-1 (Parks and Recreational Facilities in the Vicinity of the Proposed Project).

Existing electrical system components associated with the Ironwood Project are limited to the existing North Gila Substation and the existing Imperial Valley Substation. The existing system is illustrated in PEA Figure 3-2 (Existing and Proposed System Configuration). Any additional existing components, unrelated to the Ironwood Project but along the Ironwood Project alignment and within the vicinity thereof are identified on maps in PEA Figure 3-1 (Proposed Project Overview Map), and Figure 5.19-1 (Power Service and Facilities in the Proposed Project Area).

D. The Public Convenience and Necessity Require Construction and Operation of the Ironwood Project (Section VII.A.2.c)

As discussed above, the CAISO Board approved the Ironwood Project as part of the 2022-2023 Transmission Plan as a policy-driven transmission project that is needed to help mitigate the East of Miguel deliverability constraint and enable delivery of 3,000 to 10,000 MW of energy into Southern California. The East of Miguel Constraint includes transmission system limitations from thermal overloads under contingency cases in a variety of facilities. The Ironwood Project supports mitigation of the East of Miguel Constraint by connecting the existing North Gila and Imperial Valley substations with a new 500 kV circuit. The CAISO evaluated six alternatives to address the major constraints identified in the SCE Eastern, SCE Metro, and SDG&E areas, and selected the alternative that includes the Ironwood Project because it "has a lower estimated cost, so it is the preferred alternative."[25]

As discussed in Section III.E, the Ironwood Project qualifies for the rebuttable presumption of need pursuant to PU Code Section 1001.1. Because the conditions of PU Code Section 1001.1 are met, the Commission is required to find that the Ironwood Project is needed unless a party presents sufficient evidence to overcome the statutory presumption of need. If a party does present such evidence, Horizon West will provide additional evidence demonstrating that the Ironwood Project is required for the public convenience and necessity.

E. Project Cost Estimate (Section VII.A.2.d, PU Code Section 1003(c))

The estimated cost of the Ironwood Project as approved by the CAISO Board is $340 million ("Project Cost Estimate").[26] More details regarding the Project Cost Estimate are provided in Exhibit 6 (Project Cost Estimate (Public Version)) and Exhibit 6C (Project Cost Estimate (Confidential Version)). Concurrently with this Application, Horizon West is filing a motion for leave to file Exhibit 6C under seal.

As stated above, the costs of the Ironwood Project will be recovered solely through the

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[25] Exhibit 1 (2022-2023 Transmission Plan) at F-148 (Appendix F).

[26] *Id.* at 6 (Table ES-2).

CAISO TAC approved by FERC. Horizon West therefore does not seek any ratemaking determination from the Commission.

Section 1005.5(a) of the PU Code states that when the Commission issues a CPCN for a new electric transmission facility estimated to cost more than $50 million, the Commission "shall specify in the certificate a maximum cost determined to be reasonable and prudent for the facility." Horizon West has estimated the maximum reasonable and prudent cost of the Ironwood Project to be $391 million. This estimated maximum reasonable and prudent cost is consistent with CAISO's Project Cost Estimate with an additional 15 percent contingency to account for route or scope changes, final engineering design, final environmental mitigation requirements, and other factors beyond Horizon West's control that may impact the final cost. Because the Ironwood Project's rates will be set by FERC, Horizon West asks the Commission to ensure that any maximum cost it may authorize is no less than FERC's finding of the just and reasonable costs of the Ironwood Project.

F. Reasons for Selecting the Route (Section VII.A.2.e)

The proposed transmission line route, alternative routes considered, the method by which they were analyzed and compared, and the advantages and disadvantages of each are discussed in detail in Chapter 6 of the PEA and in the Routing Study.

G. Schedule of Right-of-Way Acquisition (Section VII.A.2.f)

A Project Implementation Plan showing the schedule of right-of-way acquisition and construction is attached in Exhibit 7.

H. List of Reviewing Government Agencies (Section VII.A.2.g)

Governmental agencies in the Ironwood Project area from whom Horizon West has sought input regarding siting and routing alternatives include:

- BLM: Horizon West has communicated with and met with BLM approximately monthly since August 2024. The BLM Desert District is creating a Project Charter to assign staff from various offices to the Ironwood Project to create one interdisciplinary team with specialists from several BLM offices. Monthly meetings will continue and will likely increase in frequency as the Project Charter is finalized and permitting advances. BLM has not communicated any conflicts or concerns to Horizon West about the Ironwood Project.

- USBR: Horizon West sent electronic files of proposed and alternative routes to USBR for comment throughout the first half of 2025. Horizon West also hosted a site visit in June 2025 with several departments within USBR for structure location suggestions to ensure compatibility with current and future land use. HWT has communicated with and met with BOR staff in the Project area to review routing options on June 17 and 18, 2025, and has continued to meet with BOR to solicit input on the Proposed Project and alternatives. Based upon several virtual meetings and the site visit, some structures within USBR right-of-way have been relocated to meet USBR expectations.

- CPUC: Horizon West initiated contact with CPUC regarding the Ironwood Project in 2024 and has had monthly meetings throughout 2025 with the agency's Project Manager and third-party environmental consultants. Horizon West has submitted drafts of the PEA throughout 2025 for review and feedback.

- Imperial County, California: Horizon West has met periodically with Imperial County Supervisors and County Staff from November 2024 through June 2025 to introduce the Ironwood Project and to solicit input regarding preliminary concerns and route alternatives. Imperial County has not communicated any conflicts or concerns to Horizon West about the Ironwood Project, and Horizon West's understanding is that Imperial County supports the Ironwood Project.

- Calexico, California: Between January and March of 2025, Horizon West met with the Planning Director, Mayor Pro Tem, and City Manager of the City of Calexico to provide an overview of Horizon West and the Ironwood Project. City officials asked about the scale of the Ironwood Project and planned capacity and interconnections. The City of Calexico has not communicated any conflicts or concerns to Horizon West about the Ironwood Project, and Horizon West's understanding is that the City of Calexico supports the Ironwood Project.

- Arizona Game and Fish Department ("Arizona Game and Fish"): Horizon West provided digital copies of the proposed and alternative routes to Arizona Game and Fish in June 2025 and invited them to attend the site visit in June 2025 with USBR, mentioned above. Arizona Game and Fish has not provided written comments on the Ironwood Project yet but provided routing suggestions in the field that have been incorporated into the proposed route.

- Yuma County, Arizona: Horizon West has communicated with Yuma County Supervisors and Staff during three meetings conducted between November 21, 2024, and April 9, 2025. At these meetings, Horizon West introduced the Ironwood Project, discussed routing options, and solicited Yuma County feedback. Yuma

County has not communicated any conflicts or concerns to Horizon West about the Ironwood Project.

- City of Yuma, Arizona: Horizon West met with the Mayor and City Administrators of the City of Yuma on February 21, 2025, and again with City of Yuma Interim City Administrator and Deputy City Administrator on April 10, 2025. Horizon West provided an overview of the Ironwood Project and officials provided feedback on routing options, including concerns over routing through Yuma due to construction, existing land use, and zoning constraints. City representatives expressed that the Ironwood Project would be important to supporting the City's goals for future growth.

The attached Exhibit 12 and PEA Chapter 2 (Section 2.2, Pre-filing Consultation and Public Outreach) further describe the outreach Horizon West has conducted to date regarding the Ironwood Project. Outreach also included the Fort Yuma Quechan Tribe, voluntary informal outreach to other area Tribes, and engagement with additional interested, though non-jurisdictional, public agencies. The Routing Study includes a further summary of public outreach and engagement activities, as well as a discussion of preliminary concerns, alternatives suggested, and significant outcomes of consultation and public engagement.

I. Measures to Reduce Potential Exposure to Electric Magnetic Fields (Section VII.A.2.h)

Section VII.A.2.h of GO 131-E requires a description of measures taken or proposed to reduce the potential for exposure to Electric Magnetic Fields ("EMF") from the Ironwood Project. Horizon West evaluated EMF mitigation measures in its design and construction plan and adopted low- and no-cost mitigation options. The attached Exhibit 10 provides Horizon West's Electric and Magnetic Fields Management Plan for the Ironwood Project, which may be updated after the final route is approved and detailed engineering is completed.

Horizon West incorporated low- and no-cost mitigation in accordance with Commission requirements and the Commission's EMF Design Guidelines for Electrical Facilities.[27] In 2006,

[27] Commission's EMF Design Guidelines for Electrical Facilities (July 21, 2006).

the Commission issued Decision ("D.") 06-01-042, which affirmed its prior finding that a direct link between exposure to EMF and human health effects has yet to be proven despite numerous studies, including a research program ordered by the Commission and conducted by the Department of Health Services.[28] The Commission reaffirmed its existing policy of requiring new and upgraded facilities to implement "no-cost" or "low-cost" (meaning four percent or less of the total project cost) measures to mitigate EMF.[29] The Commission policy set a target for low-cost EMF reductions to show a 15 percent or greater reduction in EMF at the utility right-of-way.[30] D.06-01-042 also addressed the mitigation measures to be required in different land use contexts and determined that low-cost measures were not required in agricultural and undeveloped areas except for permanently occupied residences, schools or hospitals located on those lands.[31]

J. Compliance with ESJ Action Plan (Section VII.A.2.i)

In February 2019, the Commission adopted the ESJ Action Plan to serve as a roadmap for implementing the Commission's policies regarding environmental and social justice. The Commission issued Version 2.0 of the ESJ Action Plan on April 7, 2022. As required by GO 131-E Section VII(A)(2)(i), the Ironwood Project complies with the goals of the Commission's ESJ Action Plan, as described in Exhibit 16 in more detail.

K. Proponent's Environmental Assessment (Section VII.A.2.j)

GO 131-E requires the Application to include a PEA or equivalent information on the environmental impact of the Ironwood Project to permit compliance with CEQA and Commission

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28 D.06-01-042 at 19 (Finding of Fact 5); *see also* D.93-11-013, in which the Commission adopted an EMF policy for electric utility facilities and power lines. Because the Commission concluded there was no reliable scientific basis for adverse health effects from power frequency EMF, the Commission declined to adopt a specific numerical standard for EMF exposure. *Id*. at *11.

29 *Id*. at 1, 22 (Ordering Paragraph 2).

30 *Id*. at 10, 21 (Finding of Fact 20).

31 *Id*. at 9, 20 (Finding of Fact 18).

Rules 2.4 and 2.5. A PEA prepared for the Ironwood Project in accordance with the Commission's PEA Guidelines,[32] the CEQA statute,[33] and the CEQA Guidelines[34] is attached as Exhibit 17.

Horizon West will perform final engineering of the Ironwood Project after the Commission has completed its CEQA review and approved the CPCN, to avoid incurring significant costs before Commission approval. Such final engineering may result in minor modifications to the project design, and under CEQA a supplemental environmental review may be required if the modifications are significant.[35] Horizon West requests that the Commission authorize the Energy Division to determine whether any potential modification to the Ironwood Project will result in new, significant environmental effects or a substantial increase in the severity of previously identified environmental effects. If the Energy Division determines that the modification meets those criteria, the Energy Division will direct Horizon West to file a petition for modification of the decision granting a CPCN and a supplemental environmental review will be performed. If the Energy Division determines that the modification is not significant, then the Energy Division will be authorized to approve the requested modifications without supplemental environmental review.

L. Notice (Section VIII.A and C)

Section VIII.A of GO 131-E requires notice of an application for a CPCN to be provided within ten days of filing by direct mail, newspaper advertisement, and posting a notice on- and off-site where the Ironwood Project will be located. Horizon West's form notice is attached as

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32 *Guidelines for Energy Project Applications Requiring California Environmental Quality Act (CEQA) Compliance: Pre-filing and Proponent's Environmental Assessments* (November 2019).

33 Pub. Resources Code § 21000 *et seq.*

34 14 Cal. Code Regs. § 15000 *et seq.*

35 CEQA Guidelines, Section 15162(a)(1), requires supplemental environmental review if the lead agency determines that "[s]ubstantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects."

Exhibit 14 and will be distributed as required within ten days after filing this Application. Horizon West consulted with the Energy Division and the Commission's Public Advisor regarding the contents of the attached notice in compliance with GO 131-E Section VIII.C.

V. PU CODE SECTION 1003 REQUIREMENTS

PU Code Section 1003 applies to the Ironwood Project because Horizon West is submitting an application for a CPCN for a transmission line that is not subject to the California Energy Commission Site Certification process (Pub. Resources Code Section 25500 *et seq*.). Below is the information required to be provided under PU Code Section 1003.

A. Preliminary Engineering and Design Information (PU Code Section 1003(a))

In accordance with PU Code Section 1003(a), preliminary engineering and design information for the Ironwood Project is provided in Chapter 3 of the PEA.

B. Project Implementation Plan (PU Code Section 1003(b) and (e))

In accordance with PU Code Section 1003(b) and (e), a Project Implementation Plan describing plans for the Ironwood Project's implementation, design, construction management, and cost control is attached hereto as Exhibit 7. The Project Implementation Plan shows how all major tasks will be integrated and includes a timetable for each major component of the Ironwood Project, as required by PU Code Section 1003(b). The Project Implementation Plan also satisfies the requirements of PU Code Section 1003(e) because it discusses the contractual and working responsibilities and interrelationship between Horizon West's management and other major parties involved in the Ironwood Project, as well as a construction progress information system and specific cost controls.

C. Cost Estimate (PU Code Section 1003(c))

In accordance with PU Code Section 1003(c), the Project Cost Estimate is attached in Exhibit 6 (Project Cost Estimate (Public Version)) and Exhibit 6C (Project Cost Estimate

(Confidential Version)). Concurrently with this Application, Horizon West is filing a motion for leave to file Exhibit 6C under seal. The cost estimate includes the costs of financing, construction, operation, maintenance, and dismantling after the useful life of the Project.

D. Cost Control (PU Code Section 1003(d))

Horizon West has the financial capability to construct, own, operate, and maintain the Ironwood Project. As explained above, Horizon West will recover its costs through the CAISO TAC approved by FERC and is not requesting the Commission to approve a transmission rate for the Ironwood Project. To comply with PU Code Section 1003(d), Horizon West is providing the attached Exhibit 13 (Annual Revenue Requirement (Public Version)), and Exhibit 13C (Annual Revenue Requirement (Confidential Version)), which provides an illustration of the expected annual revenue requirement of the Ironwood Project. Concurrently with this Application, Horizon West is filing a motion for leave to file Exhibit 13C under seal.

VI. PU CODE SECTION 1002 REQUIREMENTS

PU Code Section 1002(a) provides that "[t]he Commission, as a basis for granting any certificate pursuant to [PU Code] Section 1001 shall give consideration to the following factors: (1) community values; (2) recreational and park areas; (3) historical and aesthetic value; (4) influence on the environment . . . ." Below and in the attached PEA, Horizon West provides detailed information and analysis to facilitate the Commission's consideration of each of these statutory factors.

A. Community Values

The Ironwood Project will improve grid reliability and enable delivery of energy into California, providing benefits to customers and advancing California's energy policy goals. The Ironwood Project will provide economic benefits to local communities in the form of employment opportunities and tax revenues.

The Ironwood Project's proposed route maximizes the amount of ROW within existing mapped utility corridors. In the vicinity of the Ironwood Project there are 44 miles of land designated as an energy corridor on BLM land, and the proposed route would be sited within all 44 miles of existing energy corridor. Therefore, the Ironwood Project will be consistent with the existing development and community values.

Horizon West designed the Ironwood Project to avoid, minimize, and mitigate where feasible potential environmental impacts. As described in the PEA, Horizon West developed Applicant Proposed Measures ("APMs") to minimize impacts on the community.

Horizon West selected the proposed route after thorough consideration of other potential alternative routes, with input from prefiling outreach to governmental agencies, non-governmental organizations, Native American Tribes, the Commission's Energy Division, private landowners and homeowners' associations, other utility owners and operators, and the public. Horizon West used the collected information to further refine the route alternatives and select a proposed route.

Horizon West is committed to maintaining communication with stakeholders, including nearby residents and property owners, government agencies, Native American Tribes, and interested parties about the status and scope of the Ironwood Project. Horizon West maintains a project website for the Ironwood Project (www.ironwoodtransmission.com), which it updates regularly, and maintains a project hotline and email inbox to facilitate updates to and communication with interested parties.

B. Recreation and Park Areas

The impacts of the Ironwood Project on recreation and park areas were considered in determining the proposed route. Each alternative route considered in the Routing Study was analyzed for impacts, and the proposed route minimizes impacts to recreation and park areas compared to alternative routes.

Horizon West also considered impacts of the Ironwood Project on recreational and park areas, as described in Chapter 5.16 (Recreation) of the PEA. Horizon West identified parks and recreational facilities within one-half mile of the Ironwood Project, as listed in Table 5.16-1 of the PEA and shown on Figures 5.16-1(a), (b), and (c). The Ironwood Project is not anticipated to have any significant impacts on recreation and park areas during construction. In the PEA, Horizon West proposes APMs to mitigate or reduce impacts on recreation and park areas during construction and operation.

C. Historic and Aesthetic Values

Horizon West considered the impacts on historical and aesthetic values when determining the proposed route and analyzing alternative routes. The analysis of cultural resources is described in Section 3.6 of the Routing Study, and potential impacts to visual resources and aesthetics are analyzed in Section 3.5 of the Routing Study. The proposed route maximizes the use of existing ROWs and designated utility corridors,[36] which minimizes impacts to historical and aesthetic values compared to alternative routes.

Horizon West also considered impacts on historical and aesthetic values, as described in detail in Chapters 5.1 (Aesthetics), 5.5 (Cultural Resources), and 5.18 (Tribal Cultural Resources) of the PEA. In the PEA, Horizon West proposes APMs to minimize impacts on historical and aesthetic values during construction and operation. These APMs are described in Chapters 5.1, 5.5 and 5.18 of the PEA.

D. Influence on the Environment

The Ironwood Project's influence on the environment is addressed in the PEA and will be considered and addressed during the environmental evaluation required by CEQA. The CEQA

[36] Routing Study at 57 (Section 4.6.3, Preferred Route).

document will identify significant environmental impacts, if any, consider alternatives, and require mitigation measures as needed.

VII. REQUIREMENTS OF THE COMMISSION'S RULES

Below is a list of the informational requirements for applications for a CPCN as set forth in the Commission's Rules, with references to the location of the required information within this Application and supporting Exhibits, including the PEA.

A. Statutory Authority (Rule 2.1)

Horizon West files this Application pursuant to PU Code Sections 1001 and 1003, *et seq*., GO 131-E, and the Commission's Rules.

B. Applicant (Rule 2.1(a))

This Application is filed by Horizon West Transmission, LLC, a Delaware limited liability company formed in 2014 and qualified to do business in California, with its principal place of business at One California Street, Suite 1600, San Francisco, California 94111. Horizon West is a public utility in California, assigned utility number U222-E, and is the owner and operator of the existing Suncrest Dynamic Reactive Power Support Project located in San Diego County, California ("Suncrest Project"). Horizon West also is developing and will construct, own, and operate the Estrella Substation, which was approved by the Commission in D.24-04-011. Copies of Horizon West's Certificate of Formation with the State of Delaware and Application for Registration filed with the Secretary of the State of California previously were filed with the Commission in connection with A.15-08-027 and are incorporated herein by reference.

C. Correspondence and Communications (Rule 2.1(b))

Correspondence and communications regarding this Application should be directed to the following Horizon West representatives:

Tracy C. Davis
NextEra Energy Transmission, LLC
5920 W. William Cannon Dr., Building 2
Austin, Texas 78749
Telephone: (512) 236-3141
tracy.c.davis@nee.com

Lisa A. Cottle
Jennifer L. Garlock
Sheppard Mullin Richter & Hampton LLP
Four Embarcadero Center, 17th Floor
San Francisco, California 94111-4109
Telephone: (415) 774-3117
lcottle@sheppardmullin.com
jgarlock@sheppardmullin.com

D. Category, Need for Hearing, Issues, and Proposed Schedule (Rule 2.1(c))

Rule 2.1(c) requires applications to state "the proposed category for the proceeding, the need for hearing, the issues to be considered, and a proposed schedule." Horizon West proposes to categorize this Application as a ratesetting proceeding. This Application does not involve an enforcement investigation or a complaint and thus does not meet the definition of an "adjudicatory" proceeding under Rule 1.3(a). This Application also does not establish policy or rules affecting a class of regulated entities and thus does not meet the definition of a "quasi-legislative" proceeding under Rule 1.3(f). Because FERC will set rates and determine the cost recovery for the Ironwood Project through its approval of the TAC, this proceeding does not fit clearly within the "ratesetting" definition under Rule 1.3(g) because the Commission will not set rates or establish a mechanism that sets rates for Horizon West. Under Rule 7.1(e)(2), when a proceeding does not clearly fit into any of the categories in Rules 1.3(a), (f), and (g), the proceeding will be conducted under the rules applicable to the ratesetting category. Horizon West therefore proposes that this Application should be categorized as ratesetting.

Horizon West does not anticipate that hearings will be needed for this proceeding. Nevertheless, Horizon West proposes a schedule below that allows time for hearings, if needed.

Based on Commission precedent, the issues to be considered in this proceeding are:

1. Does the Ironwood Project serve a present or future public convenience and necessity?
2. If the CEQA Process results in an environmental impact report ("EIR"):

(a) What are the significant environmental impacts of the Ironwood Project, if any?

(b) Are there potentially feasible mitigation measures that will avoid or lessen the identified significant environmental impacts?

(c) As between the Ironwood Project and the project alternatives, which is environmentally superior?

(d) Are the mitigation measures or environmentally superior project alternatives infeasible for economic, social, legal, technological, or other considerations?

(e) To the extent that the Ironwood Project and/or project alternatives result in significant and unavoidable impacts, are there overriding considerations that nevertheless merit Commission approval of the Ironwood Project or project alternative?

3. If the CEQA Process results in a mitigated negative declaration ("MND"):

(a) Is there substantial evidence, in light of the whole record before the Commission, that the Ironwood Project as proposed or revised (to avoid or mitigate the effects to a point where clearly no significant effects would occur) will not have a significant effect on the environment?

(b) What are the mitigation measures/alternatives that will eliminate or lessen the impacts?

4. Did the Commission review and consider the environmental document (EIR or MND), was the environmental document completed in compliance with CEQA, and does it reflect the Commission's independent judgment?

5. What is the maximum prudent and reasonable cost of the Ironwood Project?

6. What, if any, are the community values affected by the Ironwood Project under PU Code Section 1002(a)(1)?

7. What are the impacts on environmental and social justice communities, including the extent to which the construction of the Ironwood Project impacts the achievement of any of the nine goals of the Commission's ESJ Action Plan?

8. Is the Ironwood Project and/or environmentally superior project alternative designed in compliance with the Commission's policies governing the mitigation of EMF effects using low-cost and no-cost measures?

9. Should the Commission grant Horizon West exemptions from certain affiliate transaction rules?

Below is Horizon West's proposed schedule for the proceeding.

Event	Date
Application Filed	September 2025
Protests and Responses	Due 30 days after publication in the Daily Calendar
Replies to Protests	Due 10 days after the last day for protests and responses
PEA Submitted to CPUC	September 2025
Scoping Ruling	November 2025
Draft EIR/MND	November 2026
Draft EIS	March 2027
Final EIR/MND	August 2027
Prehearing Conference Statements and Prehearing Conference	September 2027
Amended Scoping Ruling	October 2027
Final EIS	January 2028
Opening Testimony (if needed)	January 2028
Reply Testimony (if needed)	February 2028
Hearings (if needed)	March 2028
Opening Briefs	April 2028
Reply Briefs	May 2028
Proposed Decision	August 2028
Commission Decision	September 2028

E. Organization and Qualification (Rule 2.2, PU Code Section 1004)

Copies of Horizon West's Certificate of Formation with the State of Delaware and Application for Registration filed with the Secretary of the State of California previously were filed with the Commission in connection with A.15-08-027 and are incorporated herein by reference.

F. Financial Statements (Rules 2.3, 3.1(g))

In accordance with Rules 2.3 and 3.1(g), the most recently available balance sheet and income statement for Horizon West are attached as Exhibit 8.

G. Compliance with CEQA (Rule 2.4)

In accordance with Rule 2.4, Horizon West is submitting a PEA that complies with the Commission's CEQA Guidelines[37] in Exhibit 16.

H. Deposit for Costs for Environmental Review (Rule 2.5)

In accordance with Rule 2.5, Horizon West is submitting its deposit for preparation of the required CEQA document in the amount of $84,000, or one-third of the estimated costs to prepare the EIR of $252,000. Pursuant to Rule 1.16, Horizon West is also submitting its filing fee for its CPCN application of $680, consistent with the Commission's schedule of filing fees.

I. Full Description of the Proposed Construction (Rule 3.1(a))

In accordance with Rule 3.1(a), the proposed construction of the Ironwood Project facilities is described in Chapter 3 of the PEA.

J. Competing Utilities (Rule 3.1(b))

Horizon West was directed by the CAISO to construct, own, and operate the proposed Ironwood Project. The Ironwood Project will be operated as part of the CAISO-controlled transmission system and will not compete with any other utilities, corporations, persons, or other entities, whether publicly or privately operated. The Ironwood Project will be constructed through Imperial Valley, California within the service area of Imperial Irrigation District. Horizon West is a transmission-only utility and does not intend or propose through this Application to provide retail electric service.

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37 *Guidelines for Energy Project Applications Requiring California Environmental Quality Act (CEQA) Compliance: Pre-filing and Proponent's Environmental Assessments* (November 2019).

K. Map of Suitable Scale Showing Location or Route of the Proposed Construction (Rule 3.1(c))

A map of suitable scale showing the proposed route of the Ironwood Project, and its relation to other public utilities, corporations, persons, or entities with which the same is likely to compete, is provided as Exhibit 5 to this Application.

L. Required Permits (Rule 3.1(d))

A list of required permits for the Ironwood Project is provided in Exhibit 11.

M. Facts Showing that the Public Convenience and Necessity Require the Ironwood Project (Rule 3.1(e))

As discussed in Section III.E, the Ironwood Project satisfies the requirements in PU Code Section 1001.1 such that 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..." (PU Code § 1001.1.) Because the conditions of PU Code Section 1001.1 are met, the Commission is required to find that the Ironwood Project is needed unless a party presents sufficient evidence to overcome the statutory presumption of need. If a party does present such evidence, Horizon West will provide additional evidence demonstrating that the Ironwood Project is required for the public convenience and necessity.

N. Project Cost Estimate (Rule 3.1(f))

A Project Cost Estimate that includes the estimated cost of the proposed construction and estimated annual costs, both fixed and operating, is provided in Exhibit 6 (Project Cost Estimate (Public Version)) and Exhibit 6C (Project Cost Estimate (Confidential Version)). Concurrently with this Application, Horizon West is filing a motion for leave to file Exhibit 6C under seal.

O. Financial Ability and Information Regarding Financing (Rule 3.1(g))

Horizon West's ability to construct, own, and operate the Ironwood Project is demonstrated through its most recently available balance sheet and income statement, attached to this

Application as Exhibit 8. Horizon West will own the assets that comprise the Ironwood Project and will recover costs through the TAC approved by FERC. Horizon West intends to finance the Ironwood Project's estimated cost with a combination of equity contributions and a third-party debt facility.

P. Proposed Rates (Rule 3.1(h))

Horizon West will recover costs through the TAC approved by FERC. Horizon West's rates will be determined by FERC according to FERC's exclusive jurisdiction over rates for interstate transmission service. An illustrative annual revenue requirement for the Ironwood Project is provided in Exhibit 13 (Annual Revenue Requirement (Public Version)), and Exhibit 13C (Annual Revenue Requirement (Confidential Version)).

Q. Latest Proxy Statement by the Applicant's Parent Company (Rule 3.1(i))

Horizon West is an indirect, wholly owned subsidiary of NextEra Energy. A copy of NextEra Energy's most recent proxy statement is provided as Exhibit 9.

VIII. REQUEST FOR LIMITED EXEMPTION FROM AFFILIATE TRANSACTION RULES FOR THE IRONWOOD PROJECT

Horizon West respectfully requests limited exemptions from the Commission's affiliate transaction rules (as adopted in D. 97-12-088, D.98-08-035, and D.98-12-075, the "Affiliate Transaction Rules")[38] for the Ironwood Project. In D.18-09-030, the Commission granted Horizon West a CPCN for the Suncrest Project, and also granted Horizon West exemptions from Sections V.C., V.E., and V.G. of the Affiliate Transaction Rules with respect to the Suncrest

[38] The Affiliate Transaction Rules apply different requirements to "major" public utilities in California with gross annual operating revenues of one billion dollars or more. Because Horizon West's gross annual operating revenues in California do not equal or exceed this threshold, the requirements applicable only to "major" public utilities do not apply to Horizon West.

Project.[39] Because the Commission has indicated it requires review of exemptions from the Affiliate Transaction Rules on a project-specific basis,[40] Horizon West requests that the Commission grant Horizon West the same exemptions from the Affiliate Transaction Rules for the Ironwood Project that apply to the Suncrest Project.

Specifically, Horizon West seeks an exemption from Section V.C, V.E., and V.G. of the Affiliate Transaction Rules to allow Horizon West to use affiliate resources and facilities in connection with construction and operation of the Ironwood Project. Horizon West seeks these limited exemptions to share certain office space, information systems, engineering and operations, and employees with affiliated entities. Allowing shared use of these affiliate resources will be efficient and cost-effective and will allow Horizon West to draw on the experience and expertise of its affiliates to construct and operate the Ironwood Project.

The requested exemptions should be granted because Horizon West's operations do not present the risks that the Affiliate Transaction Rules were designed to protect against. Horizon West does not have any direct customers, retail customers, or Commission-established rates. Horizon West's operations consist exclusively of owning, operating, and maintaining transmission facilities that are under the CAISO's operational control and integrated into the FERC-regulated, CAISO-controlled transmission system. Horizon West collects rates that are regulated, reviewed, and approved by FERC. Horizon West's operations therefore do not present the risks that the Affiliate Transaction Rules are intended to address, namely cross-subsidization of utility affiliates, exercise of market power, risk of customer confusion between the utility and its affiliate, and

39 D.18-09-030 at Ordering Paragraph #4.

40 *Id*. at 48 ("[E]xemptions from the affiliate transaction rules in this proceeding do not guarantee that such waivers for other similarly structured and approved transmission projects in California as each request for waiver must be individually considered in the appropriate proceeding."); *see also*, D.24-03-010 at 13.

disclosure of private customer-specific information.[41]

For these reasons, which are explained further below, Horizon West requests an exemption from Sections V.C., V.E., and V.G. of the Affiliate Transaction Rules for the Ironwood Project.

A. Horizon West Proposes to Engage in Limited Sharing of Affiliate Resources to Construct and Operate the Ironwood Project

Horizon West proposes to enter into agreements with certain of its affiliates for administrative and operational support in developing, constructing, and operating the Ironwood Project. Horizon West currently intends to rely on the following affiliates:

- **Lone Star Transmission, LLC ("Lone Star")**: Lone Star personnel will provide operational monitoring and control of the Ironwood Project 24 hours a day, 7 days a week, from Lone Star's primary and backup control centers in Austin, Texas.
- **NextEra Energy Resources, LLC ("NEER")**: NEER's high-voltage technicians will provide engineering, construction, and environmental services to Horizon West at the Ironwood Project. NEER's technicians will also provide operations and maintenance support and ensure appropriate back-up for Horizon West's in-state staff, from its office in Palm Springs, California.
- **NextEra Energy Transmission, LLC ("NEET")**: NEET, the direct parent of Horizon West, will continue to provide transmission development and planning services in connection with the Ironwood Project.
- **Florida Power & Light Company ("FPL")**: FPL's experienced and knowledgeable engineers and electric utility professionals (including transmission and substation engineers and technicians) will be available to provide technical support and field maintenance services to Horizon West at the Ironwood Project. FPL's Power Delivery Performance and Diagnostic Center, located in Jupiter, Florida, will also provide real-time, 24/7 monitoring, and asset health assessment of the Ironwood Project.

Horizon West may contract with other affiliates to provide various corporate support services, including payroll, taxes, shareholder services, insurance, financial reporting, planning and analysis, corporate accounting, corporate security, human resources, employee records,

41 D.97-12-088, 1997 WL 812239 (Cal.P.U.C.) at 3-4.

regulatory affairs, lobbying, legal services, pension management, information technology, business management and planning, treasury, integrated supply chain procurement, and real estate.

B. Exemptions are Necessary to Allow Horizon West to Engage in the Proposed Limited Sharing of Affiliate Resources for the Ironwood Project

To allow reliance on affiliate resources as described above, Horizon West requests limited exemptions from Sections V.C., V.E., and V.G. of the Affiliate Transactions Rules.

1. Sharing of Physical Resources and Information Systems (Section V.C.)

Section V.C. of the Affiliate Transaction Rules provides that:

> A utility shall not share office space, office equipment, services, and systems with its affiliates, nor shall a utility access the computer or information systems of its affiliates or allow its affiliates to access its computer or information systems... .[42]

Horizon West seeks an exemption from the foregoing provision of Section V.C. to allow sharing of office space, office equipment, services, and systems (including information management systems) with its affiliates for use in connection with the Ironwood Project.

2. Sharing of Engineering Services and Systems Operations (Section V.E.)

Section V.E. of the Affiliate Transaction Rules identifies certain services that are appropriately shared by a utility and its affiliates, including "payroll, taxes, shareholder services, insurance, financial reporting, financial planning and analysis, corporate accounting, corporate security, human resources (compensation, benefits, employment policies), employee records, regulatory affairs, lobbying, legal, and pension management."[43] Section V.E. also allows joint

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[42] D.98-08-035, Appendix B, § V.C. at 10.

[43] *Id.*, Appendix B, § V.E. at 11 ("As a general principle, a utility, its parent holding company, or a separate affiliate created solely to perform corporate support services may share with its affiliates joint corporate oversight, governance, support systems and personnel; . . . Examples of services that may be shared include: payroll, taxes, shareholder services, insurance, financial reporting, financial planning, and

corporate oversight, governance, support systems, and personnel, but restricts such arrangements from allowing transfers of confidential information and cross subsidization as follows:

> As a general principle, a utility, its parent holding company, or a separate affiliate created solely to perform corporate support services may share with its affiliates joint corporate oversight, governance, support systems and personnel. [. . .] As a general principle, such joint utilization shall not allow or provide a means for the transfer of confidential information from the utility to the affiliate, create the opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization of affiliates.[44]

Section V.E. also identifies certain services that as a general rule may not be shared, including engineering and system operations.[45]

While several of the services that Horizon West proposes to share with affiliates with respect to the Ironwood Project are expressly identified in Section V.E. as eligible for sharing under the Affiliate Transaction Rules, others, including "engineering" and "system operations," are identified as services that, as a general rule, should not be shared out of concern for potential inappropriate cross-subsidization. Allowing Horizon West to share affiliates' engineering and system operations services at the Ironwood Project, however, does not present any risk of inappropriate cross-subsidization, as explained below. Horizon West therefore requests an exemption from Section V.E. in order to share operations and engineering services with its affiliates for use at the Ironwood Project.

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analysis, corporate accounting, corporate security, human resources (compensation, benefits, employment policies), employee records, regulatory affairs, lobbying, legal, and pension management.").

44 *Id.*, Appendix B, § V.E. at 11.

45 *Ibid*.

3. Sharing of Corporate Officers (Section V.G.)

Section V.G. of the Affiliate Transaction Rules prohibits regulated utilities from sharing employees, directors, and officers with their affiliates, except for the basic corporate support functions permitted under Section V.E. (discussed above).[46]

Horizon West has corporate officers who perform oversight activities for other affiliates and therefore requests an exemption from Section V.G. of the Affiliate Transaction Rules with respect to the Ironwood Project. The Horizon West corporate officers and directors who perform shared duties other than the basic corporate support functions permitted under Section V.E. are listed in Attachment B to the Horizon West Affiliate Transaction Rules Compliance Plan. A description of the role that each shared officer performs among the NextEra Energy affiliates is provided in Exhibit 15 to this Application.

The Horizon West corporate officers listed in Attachment B to the Horizon West Affiliate Transaction Rules Compliance Plan provide executive leadership to Horizon West and other NextEra affiliates, as well as oversight in the areas of treasury/finance, legal, procurement, human resources, business management, compliance, and corporate governance. Shared officers enable Horizon West to augment its existing operations and management practices by providing it with access to the extensive technical resources of NEET, resulting in more efficient operations. Horizon West is and will remain a separate, independent entity from its affiliates, and will maintain an appropriate level of separation.

Section 6.7 of Horizon West's Affiliate Compliance Plan also explains that Horizon West implements safeguards to ensure that Horizon West's sharing of corporate officers is not a conduit to circumvent any of the Affiliate Transaction Rules, and specifically to ensure that shared officers

46 *Id.*, Appendix B, § V.G. at 13-15.

do not allow or provide a means to (1) transfer confidential information from Horizon West to an affiliate meeting the applicability of Section II.B (a "Rule II.B Affiliate"), (2) create an opportunity for preferential treatment or unfair competitive advantage, (3) lead to customer confusion, or (4) create significant opportunities for cross-subsidization of affiliates. All NextEra employees (including Horizon West employees) are required to take an annual training regarding the Affiliate Transaction Rules and the restrictions on sharing Horizon West confidential information with Rule II.B Affiliates. The Affiliate Compliance Plan also specifies that Horizon West has established safeguards to ensure that shared employees, officers, and directors do not provide Horizon West confidential information to affiliate personnel that are restricted from accessing that information.

For the reasons discussed below, granting each of these exemptions for the Ironwood Project would be consistent with the policies underlying the Affiliate Transaction Rules and Commission precedent.

C. Granting Exemptions for the Ironwood Project Would Not Allow Cross-Subsidization, Enable the Exercise of Market Power, or Raise Customer Confusion or Privacy Concerns

In D.97-12-088, the Commission explained that the Affiliate Transaction Rules are designed to protect utility customers and promote competition by preventing cross-subsidization of utility affiliates, limiting the market power of utilities, guarding against consumer confusion between the utility and its affiliates, and protecting the privacy of customer-specific information.[47] Horizon West's operations do not present the potential for these risks to utility customers. Granting Horizon West an exemption from Sections V.C., V.E., and V.G. of the Affiliate

[47] D.97-12-088, 1997 WL 812239 (Cal.P.U.C.) at 5-6.

Transaction Rules for the construction, operation, and maintenance of the Ironwood Project therefore would not undermine their underlying purpose.

First, the goal of promoting competition that underlies the Affiliate Transaction Rules has been achieved by the competitive solicitation process through which the CAISO selected Horizon West to serve as the project sponsor for the Ironwood Project. The CAISO's competitive solicitation process is a successful example of how competition can be increased in the market for transmission services in California. Horizon West's winning bid in the CAISO's competitive solicitation demonstrates that its business model, which involves sharing resources and leveraging efficiencies across its affiliates, can allow it to provide cost savings to customers.

Second, allowing Horizon West to use affiliate resources for the construction, operation, and maintenance of the Ironwood Project would not create a risk of cross-subsidization that could impair competition. Horizon West's ability to recover costs is subject to FERC's approval of Horizon West's transmission rates, and the costs it seeks to recover will be scrutinized through the ratemaking process at FERC. There is no risk that Horizon West will inappropriately cross-subsidize its affiliates or have the ability to impair competition.

Third, Horizon West lacks the ability to exercise market power because it is exclusively a transmission-owning utility, its facilities are under the CAISO's operational control and subject to the open access terms of the CAISO Tariff, and FERC regulates the rates it can recover through its TO Tariffs via the TAC. Horizon West's facilities serve all users of the CAISO transmission system and are subject to the rules and requirements of the CAISO Tariff. Horizon West is required to implement its TO Tariffs in a non-discriminatory manner and is not able to grant preferential service to an affiliate.

Fourth, the customer protection and privacy concerns that underlie the Affiliate Transaction Rules do not apply to Horizon West, because Horizon West does not directly serve customers, provide retail service, or have access to customer information or accounts. Because Horizon West does not and will not have retail customers in California or access to any retail customer information, there is no meaningful risk of customer confusion between Horizon West and its affiliates.

The Commission previously confirmed that Horizon West's operations do not present a risk of creating the issues that the Affiliate Transaction Rules are intended to protect against.[48] In D.18-09-030, the Commission granted Horizon West certain limited exemptions from the Affiliate Transaction Rules based on findings that the policy concerns underlying the Affiliate Transaction Rules do not apply. The Commission granted Horizon West exemptions from Sections V.C., V.E., and V.G. of the Affiliate Transaction Rules, exactly as is requested in this Application, and thereby allowed Horizon West to share with its affiliates certain support services, employees, officers, and directors in connection with the Suncrest Project. The Commission found that these exemptions "are justified since [Horizon West] will not have any retail customers in California" and "there is no apparent risk of cross-subsidization of costs across [Horizon West's] Operations in California."[49] The Commission also found: "Nor is there a risk of customer confusion, or privacy violations that the Affiliate Transaction Rules were designed to address. With keen oversight provided by FERC, there is no evidence of the potential for exercise of market power to the detriment of consumers or predatory pricing."[50] The Commission's reasoning in granting the

[48] D.18-09-030 at 47-48. Note that at the time of D.18-09-030, Horizon West was known as NEET West.

[49] *Id*. at 47.

[50] *Id*. at 47-48.

limited exemptions to Horizon West for the Suncrest Project apply with equal force to the instant request for the same exemptions as to the Ironwood Project.

The Commission has similarly granted DCR Transmission, LLC ("DCRT") limited exemptions from Sections V.C., V.E., and V.G. of the Affiliate Transaction Rules to allow DCRT to rely on its affiliates for necessary corporate support services, information technology, compliance, business management and planning, treasury, integrated supply chain procurement, project management, and corporate oversight and management.[51] In granting these exemptions, the Commission confirmed that DCRT's operations do not create risks for the issues that the Affiliate Transaction Rules are designed to address, and explained:

> [T]he Commission finds that DCRT has met its burden of showing that circumstances warrant a limited exemption from Sections V.C., V.E. and V.G. With oversight by FERC for approval of DCRT's transmission rates, there is no apparent risk of cross-subsidization that could impair competition. Because DCRT is subject to open access terms in the CAISO Tariff, we do not find evidence of the potential to exercise market power. Accordingly, the Commission grants DCRT limited exemptions from Sections V.C., V.E. and V.G. of the ATRs.[52]

These findings are consistent with prior Commission decisions granting other public utilities exemptions from the Affiliate Transaction Rules. In D.20-05-012, the Commission granted Trans Bay Cable LLC ("TBC") limited exemptions from Sections V.E. and V.G. of the Affiliate Transaction Rules to allow TBC to share support services, employees, and officers and directors with its affiliates.[53] In granting these exemptions, the Commission confirmed that TBC's

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51 D.21-11-003 at 74-75.

52 *Id*. at 78.

53 D.20-05-012 at 5-6. TBC did not request, and therefore the Commission did not grant, exemption from Section V.C. in its Application No. 19-11-016.

operations, like Horizon West and DCRT, do not create the risks that the Affiliate Transaction Rules are designed to address.

In D.24-03-010, the Commission approved a settlement agreement in which LS Power Grid California, LLC ("LSPGC") was granted exemption from Sections V.C., V.E., and V.G. of the Affiliate Transaction Rules.[54] Like Horizon West, LSPGC is a transmission-only utility, the project in that proceeding was awarded to LSPGC in a competitive solicitation conducted by CAISO, the project will become part of the CAISO-controlled transmission system and be subject to the terms of the CAISO tariff, and the only means for LSPGC to recover costs is through the CAISO TAC regulated by FERC.[55]

In D.99-09-002, the Commission granted an exemption from the Affiliate Transaction Rules to an independent natural gas storage provider, Wild Goose Storage, Inc. ("Wild Goose"). The Commission determined that "[b]ecause Wild Goose does not possess market power or the ability to cross-subsidize Wild Goose's affiliates with ratepayer assets, the broad purposes behind the Affiliate Transaction Rules will not be promoted at this time by applying them to Wild

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[54] D.24-03-010 at 7-8; *see also*, D.24-01-011 at 9-10 (the Commission similarly approved a settlement between LSPGC and the Public Advocates Office that granted LSPGC a limited exemption from Sections V.C., V.E., and V.G. of the Affiliate Transaction Rules, where the proposed project was awarded in a competitive solicitation process conducted by CAISO, the costs of the project would be recovered through a TAC authorized by FERC, the project will be subject to FERC oversight and CAISO's Open Access Tariff, and LSPGC does not serve retail customers in California).

[55] A.23-01-005 at 4-5.

Goose."[56] The Commission has since found other natural gas storage providers exempt from the Affiliate Transaction Rules for the same reasons.[57]

For these reasons, Horizon West requests (i) a limited exemption from Section V.C. of the Affiliate Transaction Rules to share certain resources, including office space, office equipment, services, and systems (including information management systems) for the Ironwood Project with its affiliates, (ii) a limited exemption from Section V.E. of the Affiliate Transaction Rules to share certain corporate support services for the Ironwood Project, including transmission operations, engineering, and employee recruiting services, with its affiliates, and (iii) a limited exemption from Section V.G. of the Affiliate Transaction Rules to share certain corporate officers and directors for the Ironwood Project with its affiliates.

IX. CONCLUSION

Horizon West respectfully requests that the Commission, in a decision at the culmination of this proceeding: (1) grant Horizon West a CPCN authorizing construction of the Ironwood Project as described in this Application and the supporting documentation; (2) certify the PEA in accordance with CEQA; (3) grant the exemptions requested in Section VIII of this Application; and (4) grant such other and further relief as the Commission deems proper.

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[56] D.99-09-002, 1999 WL 1124074 (Cal.P.U.C.) at *6. In D.02-07-036, which approved Wild Goose's application to exercise market based rate authority with respect to a significantly expanded facility, the Commission found it appropriate to limit Wild Goose's ability to exercise market power by prohibiting it from engaging in storage or hub services transactions with affiliates. D.02-07-036 at 3, 18-19 (Ordering Paragraph 3(a)).

[57] D.00-05-048 at 71-72 (exempting Lodi Gas Storage, LLC from Affiliate Transaction Rules). In D.03-02-071, the Commission required Lodi Gas Storage, LLC to partially comply with the Affiliate Transaction Rules with respect to "affiliate transactions for storage or hub services (with the exception of the agreement by which Western Hub will serve as Company Manager for Lodi Holdings) . . . ." D.03-02-071 at 24 (Finding of Fact 17).

Respectfully submitted,

September 22, 2025

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Attorneys for Horizon West Transmission, LLC (U222-E)

VERIFICATION

I, Jamie Hoffman, hereby declare that I am the President of Trans Bay Cable LLC. I have read the attached APPLICATION FOR AUTHORITY TO SELL AND TRANSFER A FIFTY PERCENT INDIRECT OWNERSHIP INTEREST IN TRANS BAY CABLE LLC (U 934E) dated July 18, 2025 (“Application”). The contents of the Application are true either of my own knowledge or on my information and belief. As to the latter contents, I am informed and believe, and on that ground allege, that the matters stated in the Application are true.

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

Executed this 18th day of July, 2025 at Juno Beach, Florida.

Jamie Hoffman
President
Trans Bay Cable LLC

EXHIBIT 1

CAISO BOARD-APPROVED 2022-2023 TRANSMISSION PLAN (May 22, 2023) AND CAISO BOARD VOTING MEETING RESULTS

California ISO

2022-2023 TRANSMISSION PLAN

BOARD APPROVED
May 18, 2023

Foreword to Board Approved 2022-2023 Transmission Plan

At the May 18, 2023 ISO Board of Governors meeting, the ISO Board of Governors approved the 2022-2023 Transmission Plan.

Table of Contents

Appendices

Executive Summary

The California Independent System Operator (ISO) has prepared this 2022-2023 Transmission Plan as part of its core responsibility to identify and plan the development of solutions to comprehensively meet the future needs of the ISO-controlled transmission grid. The plan was prepared through the annual transmission planning process (TPP) that culminates in an ISO Board of Governors (Board) approved, comprehensive transmission plan.

The need for additional generation of electricity over the next 10 years has escalated rapidly in California as it continues transitioning to the carbon-free electrical grid required by the state's clean-energy policies. This in turn has been driving a dramatically accelerated pace for new transmission development in current and future planning cycles. To help ensure we have the transmission in place to achieve this transition reliably and cost-effectively, the ISO's 2022-2023 Transmission Plan reflects a much more strategic and proactive approach to better synchronize power and transmission planning, interconnection queuing and resource procurement and is put forward in close coordination with the state's primary energy planning and regulatory entities, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC).

The more proactive and coordinated strategic direction reflected in this year's transmission plan is set forth in a joint Memorandum of Understanding (MOU)[1] signed by the three parties in December 2022. The MOU tightens the linkages between resource and transmission planning activities, interconnection processes and resource procurement so California is better equipped to meet its reliability needs and clean-energy policy objectives required by Senate Bill 100.[2]

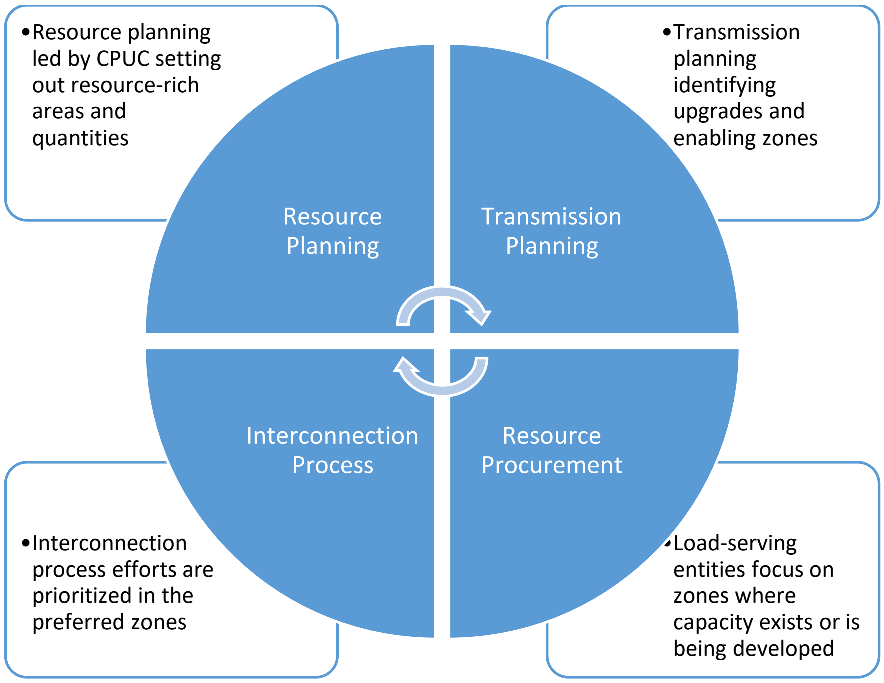
As set out in the MOU, expectations are that the CPUC[3] will continue to provide resource planning information to the ISO as it did for this transmission planning cycle. The ISO will develop a final transmission plan, initiate the transmission projects and communicate to the electricity industry specific geographic zones that are being targeted for transmission projects along with the capacity being made available in those zones. The CPUC will in turn provide clear direction to load-serving entities to focus their energy procurement in those key transmission zones, in alignment with the transmission plan.

To bring this more coordinated approach full circle, the ISO will also give priority to interconnection requests located within those same zones in its generation interconnection process.

[1] http://www.caiso.com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf

[2] SB 100, the 100% Clean Energy Act of 2018, authored by Senator Kevin De León, was signed into law by Governor Jerry Brown on September 10, 2018. Among other provisions, SB 100 built on existing legislation including SB 350 and revised the previously established goals to achieve the 50% renewable resources target by December 31, 2026, and to achieve a 60% target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[3] In addition to the needs of the jurisdictional load serving entities in the ISO's footprint, the CPUC currently works to include the needs of the publicly owned utilities and other non-CPUC-jurisdictional utilities in its resource planning efforts for the ISO balancing authority area, and this is an issue that will be receiving additional attention in future planning cycles to ensure the needs of these parties are being addressed.



This year's transmission plan is based on state projections[4] provided to the ISO in 2022 that California needs to add more than 40 gigawatts (GW) of new resources over the next 10 years, and a sensitivity[5] study projection calling for 70 GW by 2032 reflecting the potential for increased electrification[6] occurring in other sectors of the economy, most notably in transportation and the building industry. The CPUC has recently established that next year's transmission plan is to be based on this projection of 70 GW by 2033.

This plan, and the projects described on the following page, enable critical resource development, including:

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[4] In planning for the new resources required to meet system-wide resource needs, CPUC portfolios also took into account the announced retirements of approximately 3700 MW of gas-fired generation to comply with state requirements for thermal generation relying on coastal water for once-through cooling, and the planned retirement of the Diablo Canyon Power Plant. The ISO is not relying on the gas fired generation or Diablo Canyon Power Plant to meet any local capacity or grid support purposes beyond the planned retirement dates. However, the ISO must continue to ensure that they are reliably interconnected and can continue to operate through any potential extension period, so the resources are modeled in the ISO's studies for those purposes only.

[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. As well, the CPUC typically provides one or more sensitivity portfolios with higher or different levels of resource development that the ISO studies to develop transmission capacity and cost information that the CPUC uses in the next annual cycle of resource portfolio development. The sensitivity case, on its own, does not provide a basis for the ISO to approve a new transmission project. However, the ISO can consider the sensitivity case in selecting the preferred alternative to meet a need identified in the base studies.

[6] The CEC adopted the 2021 IEPR Energy Demand Forecast, 2021-2035 on January 26, 2022 [https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1] The CEC subsequently adopted 2021 IEPR Additional Transportation Electrification Scenario that on July 1, 2022, the CEC and CPUC requested the ISO utilize in the 2022-2023 Transmission Plan. [http://www.caiso.com/InitiativeDocuments/2022-2023TransmissionPlanningProcess-PortfolioTransmittalLetter.pdf]

- Over 17 GW of solar generation distributed across the state in solar development regions that include the Westlands area in the Central Valley, Tehachapi, the Kramer area in San Bernardino County, Riverside County, and also in southern Nevada and western Arizona;
- Over 3.5 GW of in-state wind generation in existing wind development regions, including Tehachapi;
- Over 1 GW of geothermal development, primarily in the Imperial Valley and in southern Nevada;
- Access for battery storage projects co-located across the state with renewable generation projects, as well as stand-alone storage located closer to major load centers in the LA Basin, greater Bay Area, and San Diego;
- The import of over 4.5 GW of out-of-state wind generation from Idaho, Wyoming and New Mexico, by enhancing corridors from the ISO border in southeastern Nevada and from western Arizona into California load centers; and
- Up to 3 GW of central coast offshore wind generation prior to the retirement of the Diablo Canyon Power Plant, and up to 5 GW after the retirement.

To achieve these outcomes, the ISO has found the need for a total of 45 transmission projects, the vast majority of which would be built in California. They range in projected costs from $4 million to $2.3 billion, for a total infrastructure investment of an estimated $7.3 billion.[7] The comprehensive analysis included screening of hundreds of options and detailed assessments of over 60 alternatives in addition to the recommended projects. The alternative analysis considered transmission upgrades, preferred resources (such as storage) and remedial action schemes. The recommended projects include, most notably:

- A new 500 kV transmission line running west from the Arizona border into southern Imperial County, new 500 kV transmission lines angling up from southern Imperial County to northern San Diego and extending into the southern LA Basin, and upgrades to the existing 500 kV and 230 kV lines along the Interstate 10 (I-10) corridor. Together, these upgrades provide access to east Riverside County, Imperial County and Arizona solar generation, Imperial Valley geothermal, and New Mexico wind generation;
- Upgrades to the Lugo–Victor–Kramer 230 kV transmission system to access north of Lugo solar resources; and
- A host of smaller upgrades improving access to other smaller resource zones.

Figure ES-1 illustrates the specific zones and capacities in each zone enabled by this Transmission Plan. The network upgrades are recommended in this plan to make all of the base amounts available and, in Southern California, to also make most of the sensitivity[8] amounts

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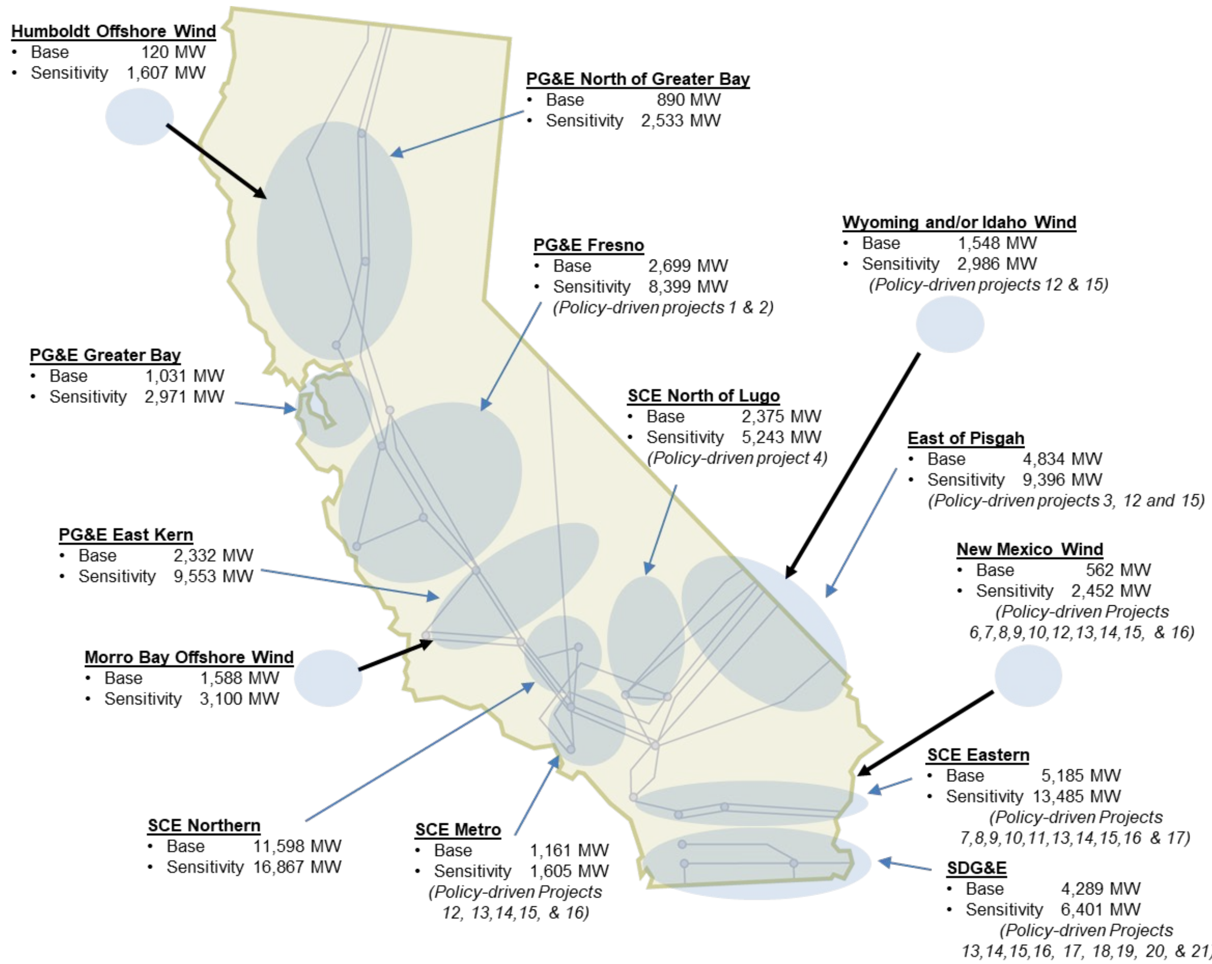
[7] The recommendation in the draft plan for the Trout Canyon-Lugo 500 kV, estimated at $2 billion, has been held back pending additional analysis of stakeholder input and a recommendation will be brought to the Board at a later date.

[8] The sensitivity portfolio was provided CPUC with higher levels of resource development that the ISO studied to develop transmission capacity and cost information that the CPUC uses in the next annual cycle of resource portfolio development. The ISO also considered the sensitivity case in selecting the preferred alternative to meet the needs identified in the base studies

available as well. As the CPUC has already determined that the sensitivity amounts in this year's plan will be the base in next year's transmission plan, the remaining network upgrades needed to achieve the sensitivity amounts will be approved next year.

Figure ES-1: Transmission Planning Zones and Capacity



The transmission projects represent significant investments that are phased in over lead times of up to eight to 10 years, which are reasonable for some of the projects to be completed. These costs translate to approximately 0.5 cents per kWh over the life of the projects, phased in as the new facilities come online. The costs for consumers are determined as part of the rate design process between utilities and their regulatory authorities. These projects are consistent with the ISO's 20 Year Transmission Outlook and co-optimized with resource planning through the CPUC's integrated resource planning process. The ISO also conducted detailed evaluations of alternatives to ensure the most efficient and cost effective long term solutions are achieved. The infrastructure investments also have tremendous reliability and economic benefits for California and its robust economy. Significant

> Transmission projects are categorized as reliability-driven projects – those needed to serve load reliably meeting NERC national standards; policy driven projects needed to deliver renewable generation to load centers to meet state clean energy goals, and economic-driven projects that will reduce the cost of energy to ratepayers by, for example, reducing grid congestion costs.

amounts of new diverse generating capacity and the transmission upgrades are required to cost-effectively bring reliable decarbonized power to California consumers and industry across all seasons of the year.

Transmission Projects Recommended for Approval

The 46 reliability-driven and policy driven transmission projects that have been found to be needed are as follows:

- ***Reliability-Driven Projects:*** Reliability projects driven by load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation represent 24 of the aforementioned projects, totaling $1.76 billion. The projects are required to reliably supply the increase in forecasted load related to electrification and electric vehicle transportation loads. The 24 projects are set out in Table ES-1.

Table ES-1 Reliability-Driven Transmission Projects Recommended for Approval

Project Name	PTO Area	Planning Area	Cost ($M)
Banta ring bus[9]	PG&E	Central Valley	17.5
Metcalf 230/115 kV Transformers Circuit Breaker Addition[9]	PG&E	Greater Bay Area	15.0
South Bay Area Limiting Elements Upgrade[9]	PG&E	Greater Bay Area	11.0
Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation[9]	PG&E	Greater Fresno	1.6
Barre 230 kV Switchrack Conversion to Breaker-and-a-Half [9]	SCE	Main	45
Mira Loma 500 kV Circuit Breaker Upgrade[9]	SCE	Main	10
Garberville area reinforcement project	PG&E	Humboldt	204.0
Tulucay-Napa #2 60 kV line resonductoring project	PG&E	North Coast & North Bay	4.6
Santa Rosa 115 kV lines reconductoring project	PG&E	North Coast & North Bay	74.0
Tesla 115 kV Bus Reconfiguration Project	PG&E	Central Valley	55.0
Lone Tree – Cayetano – Newark Corridor Series Compensation	PG&E	Greater Bay Area	25.0
Los Banos 70 kV Area Reinforcement Project	PG&E	Fresno	60.0
Redwood City Area 115 kV System Reinforcement	PG&E	Greater Bay Area	110.8
Pittsburg 115 kV Bus Reactor project	PG&E	Greater Bay Area	26
Los Banos 230 kV Circuit Breaker Replacement	PG&E	Fresno	66
Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	Fresno	184
North East Kern 115 kV Line Reconductoring Project	PG&E	Kern	256.0
Mesa Spare Transformer Installation	PG&E	Central Coast & Los Padres	24
Coolwater 1A 230/115 kV Bank Project	SCE	North of Lugo	47
Control 115 kV Shunt Reactor	SCE	North of Lugo	4
Serrano 4AA 500/230 kV Transformer Bank Addition	SCE	Main	120
Sylmar Transformer Replacement	SCE	Main	23
Antelope-Whirlwind 500 kV Line Upgrade Project	SCE	Main	6
Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Projec	SDG&E	SDG&E	375
		Total	**1,764.5**

[9] These projects have already been approved by ISO Management, ahead of the rest of the Plan being approved by the ISO's Board of Governors, pursuant to the ISO's tariff, after stakeholders were informed of Management's intention to approve, and given an opportunity to raise concerns with Management or the Board of Governors.

- In reviewing previously approved projects in the PG&E service territory in Chapter 2 that have subsequently been put on hold and were identified in the last planning cycle as needing more review, one project will continue to be on hold, another is recommended to be canceled and one is recommended to proceed with a modification to its original scope.

Policy-Driven Projects: The ISO found the need for an additional 21 transmission projects that are policy driven. These total $5.53 billion and are listed in Table ES-2. They are needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios.

Table ES-2: Policy-Driven Transmission Projects Recommended for Approval

No.	Project Name	PTO Area	Geographic Area	Cost ($M)
1	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	Fresno	50
2	Henrietta 230/115 kV Bank 3 Replacement	PG&E	Fresno	20
3	Beatty 230 kV	VEA/GLW	East of Pisgah	155
4	Lugo–Victor–Kramer 230 kV Upgrade	SCE	North of Lugo	482
5	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	SCE Eastern	50
6	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	SCE Eastern	140
7	Devers-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	40
8	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	60
9	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	SCe Eastern	65
10	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE	SCE Eastern	18
11	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	SCE Eastern	13
12	Mira Loma-Mesa 500 kV Underground Third Cable	SCE	SCE Metro	35
13	Imperial Valley–North of SONGS 500 kV Line and Substation	SDG&E	SDG&E	2,288
14	North of SONGS–Serrano 500 kV line	SDG&E / SCE	SDG&E and SCE Metro	503
15	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE	SCE Metro	1,125
16	North Gila–Imperial Valley 500 kV line	SDG&E	SDG&E (Potential Joint Project with IID)	340
17	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	APS	27
18	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	SDG&E	21
19	Reconductor TL680C San Marcos-Melrose Tap	SDG&E	SDG&E	28
20	3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	SDG&E	8
21	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	SDG&E	60
			Total	**5,528**

- The ISO has determined and included in the above transmission projects its internal transmission system requirements necessary to get access to out-of-state wind resources. These out-of-state resources have been identified by the CPUC and considered in the planning analysis by expanding the maximum import capability of the internal ISO paths to import out-of-state wind.[10] In addition to the study of the SWIP North project proposed by LS Power to access Idaho wind resources as a potential regional policy-driven transmission project discussed on the following page, the ISO has also been working with two subscription-based transmission developments seeking to bring wind resources in Wyoming (TransWest Express) and New Mexico (Sunzia) to the ISO boundary. Both transmission developments have sold transmission capacity on their planned facilities reaching to the ISO border to resource developers seeking to access California markets. That work is ongoing and the timing of those projects is driven by the developers and their subscribers.

- The ISO also continues working to refine its recommendation regarding the SWIP North project mentioned above taking into account participation interest of neighboring transmission service providers. This work will be conducted as an extension of the 2022-2023 Transmission Plan, with ISO Board of Governor approval anticipated to be sought in Q2 or Q3 of this year.
- ***Economic-Driven Projects:*** The ISO conducted several economic studies investigating opportunities to reduce total costs to ratepayers through transmission upgrades not otherwise needed for reliably accessing renewables and serving load. No projects driven solely by economic considerations are being recommended in this plan.
- ***Competitive Transmission Procurement:*** The ISO federal tariff sets out a competitive solicitation process for eligible reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the plan. The following projects – all found in Table ES-2 above - are eligible for competitive solicitation, and the ISO will provide a schedule for those processes in May, 2023:
    - Imperial Valley–North of SONGS 500 kV Line and Substation;
    - North of SONGS–Serrano 500 kV line; and
    - North Gila–Imperial Valley 500 kV line.

Other Findings and Observations

In addition to the key findings listed above, other salient observations include:

- ***Senate Bill 887:*** The Accelerating Renewable Energy Delivery Act, (Becker, 2022) provides state policy direction on a number of resource and transmission planning issues, including direction about requests the CPUC is to make of the ISO in conducting its FERC tariff-based planning processes. The ISO has considered the state policy direction provided by SB 887 in the development of this transmission plan and also conducted a review of high-priority transmission projects as requested by the CPUC for this planning cycle. The request, as set out in SB 887, was to ask the ISO to explore and

[10] The base portfolio for the 2022-2023 transmission planning cycle includes 1,500 MW of out-of-state wind resources (1,062 MW from Wyoming or Idaho and 438 MW from New Mexico) and the sensitivity portfolio includes 4,832 MW (1,500 MW from Wyoming, 1,000 MW from Idaho and 2,328 MW from New Mexico).

consider approving the highest priority transmission facilities that are needed to allow for increased transmission capacity into local capacity areas to deliver renewable energy resources or zero-carbon resources that are expected to be developed by 2035. This review took into account:

- In calculating the economic benefits of reducing the need for gas-fired generation requirements in local capacity areas, the ISO calculated the economic benefit of reduced gas-fired generation output, and also considered the economic capacity benefit of less generation being needed for local capacity even if it is still needed for system capacity. While SB 887 calls for the CPUC to provide to the ISO by March 31, 2024, resource projections expected to reduce the need to rely on non-preferred resources in local capacity areas by 2035, these projections are not yet reflected in the portfolios provided by the CPUC for the 2022-2023 Plan and the gas-fired generation is being relied upon across the planning horizon for system capacity.
- The ISO has identified 12 reliability-driven and policy-driven projects recommended for approval in this transmission plan that also reduce gas-fired generation local capacity requirements, and that are listed in Table ES-1 or Table ES-2 above:
    - Metcalf 230/115 kV Transformers Circuit Breaker Addition project (reliability-driven) – Section 2. This project is recommended to address reliability needs in the Greater Bay Area. This project, along with the two HVDC projects in the San Jose area in the 2021-2022 Transmission Plan, will reduce the local capacity requirements within the San Jose LCR sub-area.
    - The seven recommended upgrades to four existing 500 kV lines and three 230 kV lines in the SCE Eastern area (Section 3.5.8) and the addition of the third cable addition to the Mesa-Mira Loma 500 kV underground section (Section 3.5.7) will increase the 500 kV and 230 kV supply to the LA Basin area.
    - The three southern area reinforcement projects (the Imperial Valley–North of SONGS 500 kV Line and Substation, North of SONGS–Serrano 500 kV Line, and Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement projects) will increase the transmission capacity in the LA Basin by establishing a 500 kV source at the existing Del Amo 230 kV substation, and in the San Diego and LA Basin local capacity areas by establishing a new 500 kV source north of San Diego.
- The ISO has also reviewed the Pacific Transmission Expansion Project - a multi-terminal HVDC project from Diablo Canyon 500 kV substation to multiple 230 kV substations in the LA Basin area - that was submitted into the Economic Request window in the 2022-2023 transmission planning process. The ISO has also been in discussion with the Los Angeles Department of Water and Power (LADWP) about its potential interest in the project and the possibilities of a joint project;

however, the ISO is not aware of any decisions by LADWP to move forward at this time. The project can provide improved access to future offshore wind development, offload congestion on Path 26, and reduce gas-fired generation local capacity requirements. However, an ISO recommendation to approve this project will ultimately depend heavily upon the pace and volume of gas-fired generation retirements planned in the LA Basin. The ISO will continue to explore gas-fired generation retirement plans with the CPUC and work with LADWP on potential collaboration opportunities after the Plan has been approved.

- ***North Coast Offshore Wind:*** Based on the sensitivity portfolio provided by the CPUC, the ISO studied the need for transmission capacity from the North Coast for offshore wind. As the study was only informational and set the stage for future planning, no projects were recommended for approval in this 2022-2023 Plan. Given the growing volumes already identified in the North Coast in the renewable generation portfolios provided for the 2023-2024 planning cycle, the ISO expects to make a decision on North Coast transmission in next year's transmission plan.
- ***FERC Order No. 1000 Interregional Coordination Process:*** The ISO is required to coordinate its examination of potential interregional projects submitted by stakeholders into the ISO's process and the processes of the ISO's neighboring planning entities in the western interconnection - WestConnect and Northern Grid. Of the seven potential projects submitted into the ISO's 2023 interregional transmission project (ITP) submission window in the first quarter of 2022, only the North Gila – Imperial Valley No. 2 project met the requirements of an interregional transmission project in the submission validation process and received further detailed review by WestConnect and the ISO. Although WestConnect's subsequent review did not find a need for the project, it was determined to be necessary by the ISO and is recommended for approval as a regional ISO project as shown in Table ES-2.

Other Studies

As in past transmission planning cycles, the ISO undertook additional technical studies to help inform future transmission or resource planning activities. These are informational only but may be of interest to stakeholders. They include additional local capacity technical study analyses, frequency response analysis, examination of viability of congestion revenue rights, and a preliminary assessment of the transmission impact of potential reduced reliance on Aliso Canyon. The latter informational study highlights the potential need for additional transmission in the LA Basin and San Diego local capacity areas if there is reduced reliance on the Aliso Canyon Natural Gas Storage Facility in the future and is being shared with the CPUC.

These studies are set out in Chapter 6 and Chapter 7.

Conclusions and Recommendations

The 2022-2023 Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately keep pace with California's policy goals, address grid reliability requirements, identify zones of resource development and bring economic benefits to consumers. This year's plan identified 46 transmission projects, estimated to cost a total of $9.3 billion, as needed to maintain the reliability of the ISO transmission system and unlock access to renewable generation resources to meet state energy needs.

Once approved by the ISO Board of Governors at its May, 2023 meeting, the plan serves to:

- Authorize cost recovery for the 46[11] identified transmission solutions through ISO transmission rates, subject to regulatory approval; and
- Initiate the ISO's competitive solicitation process for the four eligible projects identified above.

As well, the ISO will conduct additional stakeholder and market outreach regarding the SWIP North project, as a continuation of the 2022-2023 transmission planning cycle and will conclude that effort in Q3, 2023. The ISO will also continue to explore gas-fired generation retirement plans with the CPUC and work with LADWP on potential collaboration opportunities regarding the Pacific Transmission Expansion Project both leading up to presenting this Plan to the ISO Board of Governors for approval, and after the Plan has been approved.

[11] As noted earlier, 6 reliability projects have already been approved by Management pursuant to the ISO tariff, and do not require additional approval by the Board of Governors.

Chapter 1

1 Overview of the Transmission Planning Process

1.1 Introduction

The 2022-2023 Transmission Plan reflects two significant course changes from previous years' plans, and these changes are present throughout the document. First, the ISO has reshaped the Plan to provide the proactive zonal transmission planning foundation for transformational changes the ISO is pursuing in close coordination with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to tighten linkages between resource and transmission planning activities, interconnection processes and resource procurement. Second, the Plan acts on and responds to the rapid escalation in the projected resource requirements over the next 10 to 15 years to meet California's clean-energy needs. The projected incremental resource requirements in this year's Plan, for example, climbed fourfold compared to the 2020-2021 Plan prepared only two years ago, and the pace is climbing in next year's plan as well.

As part of these transformational changes and to help shape and inform the generator interconnection process and procurement while also enhancing the state being able to achieve its reliability and decarbonization goals in a timely and cost-effective manner, the ISO is adopting a much more proactive approach to transmission planning. This new, more proactive, targeted zonal approach is grounded in the policy and reliability needs of the state. Our strategic intent in drafting the plan in this manner is that it will take into account priority zones identified in resource portfolios to develop the transmission infrastructure required and recommended for approval.

These foundational changes to our planning process build on enhancements and improvements to the ISO's regional transmission planning that have already been moving forward, including introduction in February 2022 of a 20-Year Transmission Outlook framework that is outside the tariff-based project approval planning process. This 20-Year Outlook framework was also coordinated with, and supported by, the CEC and CPUC, particularly in the development of customized 2040 resource portfolios under the auspices of the CEC's SB 100 activities and responsibilities.

The ISO relies in particular on the CPUC for its lead role in developing resource forecasts for the 10-year planning horizon, with both the ISO and CEC providing input to the CPUC for those resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements. The MOU mentioned in the Executive Summary of this plan that was signed by the three parties in December 2022 reaffirms our respective roles and commitments to ensure we are working in concert with one another. As such, the MOU also sets the overall strategic direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement so the three entities are synchronized in working for the timely integration of new resources.

In the 10-plus years since the ISO redesigned its transmission planning process, and subsequently adapted it to meet provisions of Order No.1000 from the Federal Energy

Regulatory Commission (FERC), challenges that have been placed on the electricity system – and correspondingly on the transmission system -- have evolved and grown substantially. The ISO understands that the industry is now well into an inflection point marking a significant escalation in the rate of growth in renewable resources and renewable integration resources. To contextualize this increase, it is helpful to compare the resource plans in the past three transmission plans with what is expected next year. The 2020-2021 transmission plan was based on state agency forecasts calling for approximately 1000 megawatts (MW) of additional generating capacity per year over the next 10 years. Just one year later, that 10-year forecast that informed the next plan was based on a projection calling for adding 2700 MW of generating capacity per year. For this year's plan, the 10-year projection calls for adding more than 4000 MW per year and the portfolios for next year's plan identify resource requirements of approximately 7000 MW per year.[12] The continuing growth in these numbers will by next year represent a sevenfold increase in annual requirements from the 2020-2021 Transmission Plan approved in March, 2021. The 2022-2023 transmission plan is a transitional step, recognizing the ISO and industry at-large are not yet positioned within this single planning cycle to address the full impact of the pivot to these new challenges. In addition to considering significantly larger resource portfolios, the ISO is also considering in this planning cycle more extensive system upgrades in several areas that are supported by relevant considerations and information beyond the resource portfolios provided by the CPUC. This approach recognizes that the requirements expected in next year's transmission planning process will call for an even faster pace of resource development. It also allows several low-risk projects to proceed now, providing for a more balanced development workload given that additional projects will also be initiated next year. The increased capacity provided by those upgrades, on top of what is called for in the current year's portfolios, will create additional options for load-serving entities conducting procurement to meet mid-term resource requirements.

The accelerating pace of resource development called for over the next 10 years is driven by numerous factors, including:

- The escalating need to decarbonize the electricity grid because of emerging climate change impacts;
- The expected electrification of transportation and other carbon-emitting industries, which is driving higher electricity forecasts;
- Concerns regarding reduced access to opportunity imports as neighboring systems also decarbonize;
- Greater than anticipated impacts of peak loads shifting to later-day hours when solar resources are not available; and
- The need to maintain system reliability while planning for the retirement of gas-fired generation relying on coastal waters for once-through cooling and the Diablo Canyon Power Plant.

[12] Page 11, Day 2 Presentation, September 27-28, 2021 Stakeholder Meeting, http://www.caiso.com/InitiativeDocuments/Day2Presentation-2022-2023TransmissionPlanningProcessSep27-28-2021.pdf

These resource requirements, on the path to total decarbonization of the grid and discussed in more detail in Section 1.4, will call for greater volumes of solar photovoltaic resources and battery storage, as well as greater diversity beyond the current focus on those resource types. Geothermal resources, new out-of-state renewable resources and offshore resources all are expected to play greater roles. This will create unique challenges in the planning and interconnection processes. Meeting those challenges requires adaptations and enhancements to existing processes and efforts.

Simultaneous with this shift in planning longer-term resource requirements, the CPUC has made significant strides in authorizing new resource procurement. The CPUC adopted Decision (D.) 19-11-016 on November 7, 2019, which ordered procurement of 3,300 MW of incremental resources, with 50% required to be online by August 2021. As a part of a separate proceeding (R.20-05-003), the CPUC adopted D.21-06-035 on June 24, 2021 to address mid-term reliability needs of the electricity system within the ISO's balancing authority area. This decision requires at least 11,500 MW of additional procurement, with 2,000 MW required by August 2023; 6,000 MW by June 2024; 1,500 MW by June 2025; and 2,000 MW of long lead-time resources by June 2026. In that same proceeding, on February 23, 2023, the CPUC adopted Decision (D.) 23-02-040, which ordered supplemental mid-term reliability procurement of an additional 2000 MW in each of 2026 and 2027.[13]

Reacting to previously approved authorizations and numerous signals about the accelerated pace of adding resources, the resource development industry responded with a record-setting number of new interconnections requests in April, 2021. The ISO received 373 new interconnection requests in its Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[14] The ISO assumed that the unprecedented number of projects studied in Phase I would, for a number of reasons, result in a large percentage of projects withdrawing, making for a much more reasonable number of projects needing to be studied in Cluster 14 Phase II. But that high withdrawal rate did not materialize, as 205 projects are proceeding into Phase II studies, a higher than normal percentage of advancing projects.

Resource Interconnections:

In parallel with the transmission planning changes being made and reflected in the Plan, the ISO is moving forward with corresponding changes in the generation interconnection process. It released an issues paper[15] on March 6, 2023 launching the ISO's 2023 Interconnection Process Enhancements initiative, focusing on making significant and transformative improvements regarding coordination of resource planning, transmission planning, interconnection queuing and power procurement to achieve state reliability and policy needs.

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[13] In ordering an additional 4000 MW of additional capacity (2000 MW each in 2026 and 2027, (D.) 23-02-040 allowed the 2000 MW of long lead-time resources ordered in the earlier D.21-06-035 to shift from June 2026 to June 2028 recognizing the challenges of bringing those long-lead time resources online by 2026

[14] ISO Board of Governors July 7, 2021 Briefing on renewable and energy storage in the generator interconnection queue, http://www.caiso.com/Documents/Briefing-Renewables-GeneratorInterconnection-Queue-Memo-July-2021.p

[15] http://www.caiso.com/InitiativeDocuments/Issue=Paper-and-Straw-Proposal-Interconnecton-Process-Enhancements-2023-Mar132023.pdf

In recent years, given California's ambitious decarbonization goals and the large quantities of new clean resources it will take to meet them, the ISO has been receiving hundreds of interconnection requests annually from potential resource developers. Many of these requests are not located in areas considered optimal for additional transmission development, as determined by regulators and load-serving entities. With the ISO's interconnection application queue inundated with applications, current processes need to be re-imagined to ensure resource procurement and queuing are effectively shaped and informed to take advantage of transmission and interconnection capacity that exists or is already planned and under development, and to align with the transmission upgrades necessary for longer-term resource development.

Procurement and Project Execution:

The ISO is also taking on additional efforts to:

- Coordinate with the CPUC, CEC, and the Governor's Office of Business and Economic Development (GO-Biz) to identify and help mitigate issues that could delay new resources meeting in-service dates;
- Together with the CPUC, work with the participating transmission owners in hosting the Transmission Development Forums held quarterly to improve the transparency of the status of transmission projects focusing on network upgrades approved in prior ISO transmission plans, or that resources with executed interconnection agreements are dependent on;
- Provide more information publicly regarding where resources are able to connect to the grid with no or minimal network upgrade requirements, to assist load-serving entities to shape their procurement activities towards areas and resources that are better positioned to achieve necessary commercial operation dates; and
- Coordinate with the CPUC regarding the progress of procurement activities by load-serving entities and assessing the timeliness of those procured resources meeting near and mid-term reliability requirements.

These enhancements and coordination efforts will collectively support and help the state reach its renewable energy objectives reliably.

1.2 Key Inputs

This Section 1.2 provides background and detail on key load and resource forecast inputs into the 2022-2023 transmission planning process.

1.2.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

1.2.1.1 Base Forecasts

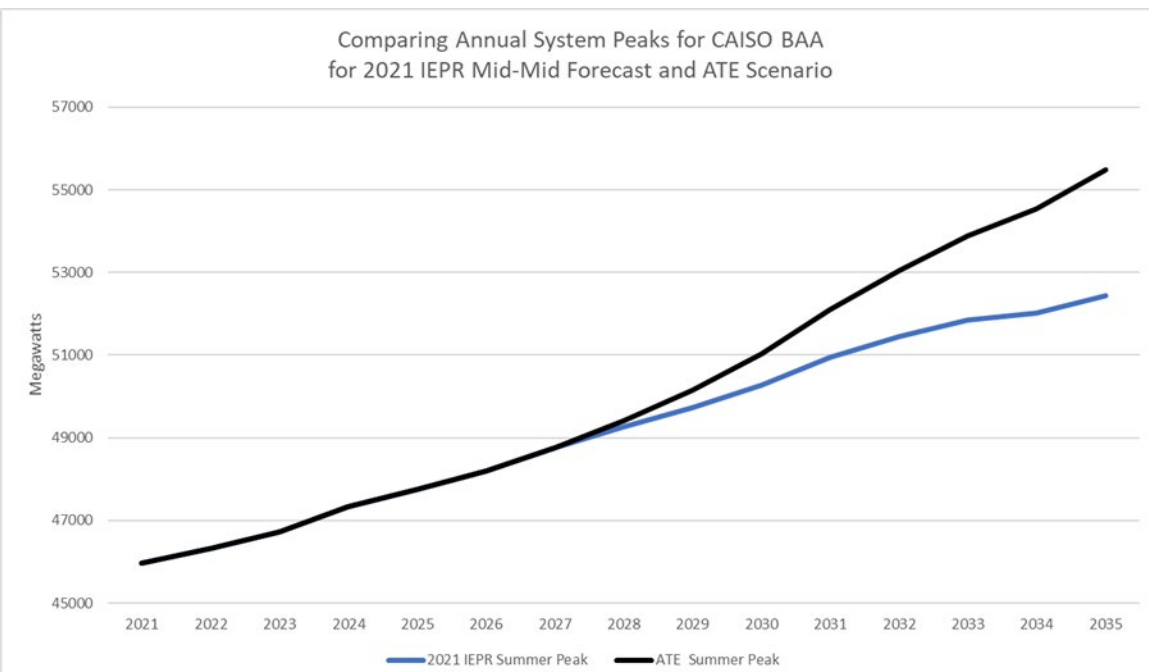
As discussed earlier, the ISO relies on load forecasts and load modifier forecasts prepared by the CEC through its Integrated Energy Policy Report (IEPR) processes. The combined effect of changing customer load patterns and evolving load modifiers is particularly important, and has driven the need for far more attention not only on peak loads and total energy consumption but also on the shape of the aggregate customer load shape on an hourly, daily, and seasonal basis.

The rapid deployment of behind-the-meter rooftop generation in particular has driven changes in forecasting, planning and operating frameworks for both the transmission system and generation fleet. It has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — to shift to a time outside of the traditional daily peak load period. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted out of the window when grid-connected solar generation is available to later times of the day.

Further developments related to load electrification due to fuel switching and electric vehicle deployment and goals have led to a significant increase in energy and demand forecasts starting in the year 2028 and beyond.

The CEC adopted the 2021 IEPR Energy Demand Forecast, 2021-2035 on January 26, 2022.[16] On July 1, 2022, the CEC and the CPUC submitted a letter to the ISO requesting it use in this year's Transmission Plan the 2021 IEPR Additional Transportation Electrification scenario developed by the CEC, which has higher loads than the 2021 IEPR forecast the ISO had originally planned to use.[17] The ISO has acceded to this request and Figure 1.2-1 provides a comparison for the summer peak of the CEC's adopted 2021 IEPR Energy Demand Forecast to the 2021 IEPR Additional Transportation Electrification Scenario.

Figure 1.2-1 Comparison of CEC's adopted 2021 IEPR Energy Demand Forecast to the 2021 IEPR Additional Transportation Electrification Scenario



[16] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1

[17] http://www.caiso.com/InitiativeDocuments/2022-2023TransmissionPlanningProcess-PortfolioTransmittalLetter.pdf

1.2.2 Resource Planning and Portfolio Development

As discussed earlier with regard to the joint MOU signed in December 2022, the ISO relies extensively on coordination with the state energy agencies, in particular with the CPUC that takes the lead in developing resource forecasts for the 10-year planning horizon with input from the CEC and ISO. These resource forecasts are provided in the form of resource portfolios, with input also received on other key assumptions. In recent years, the focus has been on achieving 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB), in coordination with the CPUC and CEC, as directed by Senate Bill (SB) 350.[18] These targets also meet or exceed the current 2030 renewables portfolio standard requirement established by Senate Bill 100.[19] The past focus has also been on establishing a reasonable trajectory to meeting 2045 renewables portfolio standard goals that were also established in SB 100.

The CPUC provided to the ISO via Decision (D) 22-03-004[20] issued on February 15, 2022, a base case and sensitivity portfolio for use in this planning cycle. The base case, provided for reliability and policy-driven study, meets the 46 million metric ton (MMT) greenhouse gas (GHG) emissions target by 2032.

In transferring the sensitivity portfolio, the CPUC called on the ISO:

1. To study the 30 million metric ton (MMT) High Electrification policy-driven sensitivity portfolio transmitted herein as in the 2022-23 TPP High Electrification Sensitivity Scenario; and
2. To continue studying the deliverability needs and corresponding transmission needs related to out-of-ISO long-lead time resources, such as out-of-state wind and geothermal resources beyond the CAISO's balancing area authority.

These portfolios also took into account the announced retirements of approximately 3700 MW of gas-fired generation to comply with state requirements for thermal generation relying on coastal

[18] SB 350, The Clean Energy and Pollution Reduction Act of 2015 (Chapter 547, Statutes of 2015) was signed into law by Governor Jerry Brown on October 7, 2015. Among other provisions, the law established clean energy, clean air, and greenhouse gas (GHG) reduction goals, including reducing GHG to 40% below 1990 levels by 2030 and to 80% below 1990 levels by 2050. The law also established targets to increase retail sales of qualified renewable electricity to at least 50% by 2030 that have now been superseded by the provisions of Senate Bill 100.

[19] SB 100, the 100% Clean Energy Act of 2018, also authored by Senator Kevin De León, was signed into law by Governor Jerry Brown on September 10, 2018. Among other provisions, SB 100 built on existing legislation including SB 350 and revised the previously established goals to achieve the 50% renewable resources target by December 31, 2026, and to achieve a 60% target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[20] Decision 22-02-004 released on February 10, 2022 for the Decision Adopting 2021 Preferred System Plan, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF

water for once-through cooling,[21] and the announced retirement of the Diablo Canyon Power Plant.[22]

1.2.2.1 Consideration of the reliance on the gas-fired generation fleet

In developing the base portfolio for the 2022-2023 transmission planning cycle, the CPUC's modeling showed that while no new natural gas-fired power plants are identified in the 2031 new resource mix, existing gas-fired plants – other than those relying on once-through-cooling and scheduled for retirement - are needed in 2032 as operable and operating resources, providing a renewable integration service. Accordingly, to align with the CPUC's assumptions, the ISO has not presumed retirement regardless of age.

The ISO notes that existing legislation[23] calls for the CPUC to provide to the ISO by March 31, 2024, resource projections that are expected to reduce by 2035 the need to rely on non-preferred resources in local capacity areas. These projections are not yet reflected in the portfolios provided by the CPUC for the 2022-2023 Plan.

1.2.2.2 Offshore Wind Generation

Starting with the 2021-2022 transmission planning process and the 20-Year Transmission Outlook, the ISO began assessing the transmission capabilities for integrating offshore wind in the central coast and northern coast areas.

The analysis indicated there is transmission capability in the central coast of approximately 5,300 MW around the Diablo Canyon Power plant that was to be retiring by the end of 2025, and the Morro Bay area where gas-fired generation has retired. It should be noted that the owners of the Diablo Canyon Power Plant retain certain deliverability retention options for repowering that can remain in effect for up to three years following the retirement of the nuclear plant. With Diablo online or deliverability retained, capacity available in the area for the interconnection of offshore wind would be about 3,000 MW. In the northern coast area, the integration of offshore wind will require transmission development for the capacities identified in the CPUC sensitivity portfolios.

In this year's planning cycle, the ISO has continued this assessment with 1,588 MW of offshore wind in the base portfolio in the Morro Bay call area and increasing to 3,100 MW in in the central

[21] The Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) has recommended the State Water Resources Control Board (SWRCB) extend the compliance date from December 31, 2023 to December 31, 2026 for some once-through cooling (OTC) gas-fired generation in the ISO footprint to achieve compliance with state policies on the use of coastal and estuarine waters for power plant cooling. The recommendation to extend the OTC policy compliance dates for Alamitos Units 3, 4, and 5, Huntington Beach Unit 2, and Ormond Beach Units 1 and 2 beyond current December 31, 2023 retirement dates is contingent on these resources participating in the Electricity Supply Strategic Reliability Reserve Program (Strategic Reserve) established through Assembly Bill 205 (AB 205), which was signed by Governor Newsom on June 30, 2022. Pursuant to AB 205, Strategic Reserve resources are to be accessed to maintain reliability during extreme events beyond traditional resource planning requirements or other emergency conditions..

[22] Senate Bill 846 (SB 846), authored by Senator Bill Dodd, was signed by Governor Newsom on September 2, 2022. Among other provisions, SB 846 established that the CPUC shall not include the energy, capacity, or any attribute from Diablo Canyon Unit 1 beyond November 1, 2024, or Unit 2 beyond August 26, 2025, in the adopted integrated resource plan portfolios, resource stacks, or preferred system plans.

[23] SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

coast area and 1,500 MW in the Humboldt call area in the sensitivity portfolio. The ISO has continued to assess transmission alternatives, particularly in the north coast area in this planning cycle and will continue to do so in next year's planning cycle, where the Humboldt call area offshore wind resources are in the base portfolio.

1.3 The Transmission Planning Process

The transmission plan's primary purpose is to identify, using the best available information at the time the plan is prepared, needed transmission facilities based upon three main categories of transmission solutions: reliability, public policy, and economic needs. The ISO may also identify in the transmission plan any transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects, or provide for merchant transmission projects. In recommending solutions for identified needs, the ISO takes into account an array of considerations, with advancing the state's objectives of a cleaner future grid playing a major part in those considerations.

Reliability-driven needs:

The ISO identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards and Western Electricity Coordinating Council (WECC) regional criteria, as well as the ISO's own transmission planning standards. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2022-2023 planning cycle, ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable NERC reliability standards.[24] The ISO performed this analysis across a 10-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions. The ISO assessed the transmission facilities under ISO operational control, which range in voltage from 60 kV to 500 kV. The ISO also identified plans to mitigate observed concerns considering upgrading transmission infrastructure, implementing new operating procedures, installing automatic special protection schemes, and examining the potential for conventional and non-conventional resources (preferred resources including storage) to meet these needs. Although the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades and work with the relevant parties and agencies to seek their implementation.

[24] This document provides detail of all study results related to transmission planning activities. However, consistent with the changes made in the 2012-2013 transmission plan and subsequent transmission plans, the CAISO has not included in this year's plan the additional documentation necessary to demonstrate compliance with NERC and WECC standards but not affecting the transmission plan itself. The CAISO has compiled this information in a separate document for future NERC/FERC audit purposes. In addition, detailed discussion of material that may constitute Critical Energy Infrastructure Information (CEII) is restricted to appendices that the CAISO provides only consistent with CEII requirements. The publicly available portion of the transmission plan provides a high level, but meaningful, overview of the comprehensive transmission system needs without compromising CEII requirements.

Policy-driven needs:

Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support local, state, and federal directives. In recent transmission planning cycles, the focus of public policy analysis has been predominantly on planning to ensure achievement of California's renewable energy goals. In the past, the focus of the goals was the renewables portfolio standard (RPS) set out in various legislation; first the trajectory to achieving the 33% renewables portfolio standard set out in the state directive SBX1-2 , and then the 60% renewables portfolio standard by 2030 objective in Senate Bill (SB) 100[25] that became law in September, 2018. More recently, the focus has shifted to the more aggressive 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB), in coordination with the CPUC and CEC as directed by SB 350[26] that would also meet or exceed the renewables portfolio standard requirement and reasonably establish a trajectory to meeting 2045 RPS goals established in SB 100. Section 1.4 provides specific details.

Economic-driven needs:

Economic-driven solutions are those that provide net economic benefits to consumers as determined by ISO studies, which include a production simulation analysis. Typical economic benefits include reductions in congestion costs and transmission line losses and access to lower cost resources for the supply of energy and capacity. As renewable generation continues to be added to the grid, with the inevitable economic pressure on other existing resources, economic benefits will also have to take into account cost-effective solutions to mitigate renewable integration challenges and potential reductions to the generation fleet located in local capacity areas.

Over the past three planning cycles, the ISO has programmatically studied the economic benefits of transmission and combinations of transmission upgrades and storage to reduce reliance on gas-fired generation in local capacity areas. In this 2022-2023 transmission planning study, the focus has been on specific economic study requests whether in or outside local capacity areas.

Comprehensive planning:

Although the ISO's planning process considers reliability, public policy, and economic projects sequentially, it allows the ISO to revisit projects identified in a prior stage if an alternative project identified in a subsequent stage can meet the previously identified need and provide additional benefits not considered earlier in the process. Thus, the ISO's iterative planning process ultimately allows the ISO to consider and approve transmission projects with multiple benefit

[25] SB 100, the 100% Clean Energy Act of 2018, authored by Senator Kevin De León, was signed into law by Governor Jerry Brown on September 10, 2018. Among other provisions, SB 100 built on existing legislation including SB 350 and revised the previously established goals to achieve the 50% renewable resources target by December 31, 2026, and to achieve a 60% target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[26] SB 350, The Clean Energy and Pollution Reduction Act of 2015 (Chapter 547, Statutes of 2015) was signed into law by Governor Jerry Brown on October 7, 2015. Among other provisions, the law established clean energy, clean air, and greenhouse gas (GHG) reduction goals, including reducing GHG to 40% below 1990 levels by 2030 and to 80% below 1990 levels by 2050. The law also established targets to increase retail sales of qualified renewable electricity to at least 50% by 2030 that have now been superseded by the provisions of Senate Bill 100.

streams (e.g., reliability, public policy, and economic) and to modify or upsize transmission solutions identified in earlier stages to achieve additional benefits. For example, the ISO's transmission planning process does not allow earlier-identified reliability projects to reduce the benefits that potential economic projects might produce. That is because the ISO's sequential process allows it to "back out" of previously identified reliability projects inside the planning cycle and count the avoided cost of a separate reliability project as an economic benefit. This is an important distinction, as it is critical to avoid the misconception that a project must be supported by solely reliability benefits, *or* policy benefits, *or* economic benefits exclusively, *i.e.*, the ISO does not approve projects through a siloed approach.

Consideration of Interregional Transmission Solutions:

A final step in the development of recommendations in each year's transmission plan is the consideration of potential interregional transmission solutions through a biennial process in place with the ISO's neighboring planning regions, WestConnect and Northern Grid, pursuant to each party's coordinated processes established under FERC Order No. 1000. Through that process, each planning entity assesses if it has regional needs that an interregional project can meet more efficiently and cost-effectively, and if so, the cost allocation that would result based on each party's benefits. The actions taken by the ISO in each year's transmission planning cycle differ based on if that planning cycle is the first or second year of the biennial coordination process. The 2022-2023 transmission planning cycle is the first year of the two-year interregional coordination planning cycle.

Other study efforts:

In addition to the consideration of reliability, policy-driven, and economic-driven needs and solutions, this year's transmission plan also considered:

1. Local Capacity Requirement Studies: Near and mid-term local capacity technical studies were prepared for 2023 and 2027, respectively, as part of the annual study process supporting the state's resource adequacy program for the 2023 resource adequacy compliance year. These studies also provide the basis for determining the need for any ISO "backstop" capacity procurement that may be necessary once the load-serving entity procurement is submitted and evaluated. Consistent with past practices, each of these studies identified the extent to which storage could meet the needs in local capacity areas in lieu of gas-fired generation. The ISO also conducts a long-term local capacity requirements study every second year to further support state resource planning efforts. The long-term local capacity requirements study is conducted every second planning cycle and has been performed in the 2022-2023 planning cycle.
2. The 2022-2023 Transmission Plan also continued migrating certain special studies (*e.g.*, frequency response studies) into a more permanent category of "other studies" within the transmission plan itself, now that the ISO has identified a need to perform this analysis on an annual basis.

1.3.1 Structure of the Transmission Planning Process

The annual planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. For example, the 2022-2023 planning cycle began in January 2021 and concluded in March 2022.

1.3.1.1 Phase 1

Phase 1 includes establishing the assumptions and models for use in the planning studies, developing and finalizing a study plan, and specifying the public policy mandates that planners will adopt as objectives in the current cycle. This phase takes roughly three months from January through March of the beginning year.

The unified planning assumptions establish a common set of assumptions for the reliability and other planning studies the ISO performs in Phase 2. The starting point for the assumptions is the information and data derived from the comprehensive transmission plan developed during the prior planning cycle. The ISO adds other pertinent information, including network upgrades and additions identified in studies conducted under the ISO's generation interconnection procedures and incorporated in executed generator interconnection agreements (GIA). In the unified planning assumptions, the ISO also specifies the public policy requirements and directives that it will consider in assessing the need for new transmission infrastructure.

Consistent with past transmission planning cycles and as discussed above in Section 1.2, development of the unified planning assumptions for this planning cycle continued to benefit from the ongoing coordination efforts between the CPUC, CEC, and ISO, building on the staff-level, inter-agency process alignment forum in place to improve infrastructure planning coordination within the three core processes:

- The CEC's long-term resource planning produced as part of SB 100-related activities and long-term forecasts of energy demand produced as part of its biennial Integrated Energy Policy Report (IEPR);
- The CPUC's biennial Integrated Resource Planning (IRP) proceedings; and
- The ISO's annual Transmission Planning Process (TPP).

The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolios, and are discussed in more detail in Section 1.4.

The study plan describes the computer models and methodologies to be used in each technical study, provides a list of the studies to be performed and each study's purpose, and lays out a schedule for the stakeholder process throughout the entire planning cycle. The ISO posts the unified planning assumptions and study plan in draft form for stakeholder review and comment. Stakeholders may request specific economic planning studies to assess the potential economic benefits (such as congestion relief) in specific areas of the grid. The ISO then selects high-priority studies from these requests and includes them in the study plan published at the end of Phase 1. The ISO may modify the list of high-priority studies later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

1.3.1.2 Phase 2

In Phase 2, the ISO performs studies to identify solutions to meet the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 12 months and ends with Board approval of the transmission plan. Thus, Phases 1 and 2 take 15 months to complete. Identifying non-transmission alternatives that the ISO is relying upon in lieu of transmission solutions also takes place at this time. It is critical that parties responsible for approving or developing those non-transmission alternatives are aware of the reliance being placed on those alternatives.

In this phase, the ISO performs all necessary technical studies, conducts a series of stakeholder meetings and develops an annual comprehensive transmission plan for the ISO-controlled grid. The comprehensive transmission plan specifies the transmission solutions required to meet the infrastructure needs of the grid, including reliability, public policy, and economic-driven needs. Accordingly, the ISO conducts the following major activities:

- Performs technical planning studies described in the Phase 1 study plan and posts the study results;
- Provides a request window for stakeholders to submit reliability project proposals in response to the ISO's technical studies, demand response, storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs, Location Constrained Resource Interconnection Facilities project proposals, and merchant transmission facility project proposals;
- Evaluates and refines the portion of the conceptual statewide plan that applies to the ISO system as part of the process to identify policy-driven transmission elements and other infrastructure needs that will be included in the final comprehensive transmission plan;
- Coordinates transmission planning study work with renewable integration studies performed by the ISO for the CPUC integrated resource planning proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff Section 24.4.6.6(g);
- Reassesses, as needed, significant transmission facilities in Generator Interconnection Procedures (GIP) Phase 2 cluster studies to determine — from a comprehensive planning perspective — whether any of these facilities should be enhanced or otherwise modified to more effectively or efficiently meet overall planning needs;
- Performs an analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[27] which are intended to

[27] Pursuant to the ISO tariff, the transmission plan may designate both category 1 and category 2 policy-driven solutions. Using these categories better enables the CAISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key

minimize the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner;

- Identifies additional category 2 policy-driven potential transmission facilities that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle;
- Performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan;
- Performs technical studies to assess the reliability impacts of new environmental policies such as restrictions on the use of coastal and estuarine waters for power plant cooling, which is commonly referred to as once-through cooling and AB 1318 legislative requirements for ISO studies on the electrical system reliability needs of the South Coast Air Basin;
- Conducts stakeholder meetings and provides public comment opportunities at key points during phase 2; and
- Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan that the ISO posts in draft form for stakeholder review and comment at the end of January and presents to the Board for approval at the conclusion of phase 2.

Board approval of the comprehensive transmission plan at the end of Phase 2 constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities, and the economic-driven facilities specified in the plan. The Board's approval enables cost recovery through ISO transmission rates of those transmission projects included in the plan that require Board approval.[28] As indicated above, the ISO solicits and accepts proposals in Phase 3 from all interested project sponsors to build and own the regional transmission solutions that are open to competition.

By definition, category 2 solutions identified in the comprehensive plan are not authorized to proceed after Board approval of the plan, but are instead re-evaluated during the next annual cycle of the planning process. At that time, based on relevant new information about the patterns of expected development, the ISO will determine whether the category 2 solutions should be elevated to category 1 status, remain as category 2 projects for another cycle, or be removed from the transmission plan.

factors that materially affect the determination of what transmission is needed. Section 24.4.6.6 of the ISO tariff specifies the criteria considered in this evaluation.

[28] Under existing tariff provisions, ISO management can approve transmission projects with capital costs equal to or less than $50 million. The ISO includes such projects in the comprehensive plan as pre-approved by ISO management and not requiring Board approval.

1.3.1.3 Phase 3

Phase 3 includes the competitive solicitation for prospective developers to build and own new regional transmission facilities identified in the Board-approved plan. In any given planning cycle, Phase 3 may not be needed, depending on whether the final plan includes regional transmission facilities that are open to competitive solicitation in accordance with criteria specified in the ISO tariff.

In addition, the ISO may incorporate into the annual transmission planning process specific transmission planning studies necessary to support other state or industry informational requirements to efficiently provide study results that are consistent with the comprehensive transmission planning process. In this cycle, these focus primarily on grid transformation issues and incorporating renewable generation integration studies into the transmission planning process.

Phase 3 takes place after the Board approves the plan if there are projects eligible for competitive solicitation. Projects eligible for competitive solicitation include regional transmission facilities (*i.e.*, transmission facilities 200 kV and above) except for regional transmission solutions that are upgrades to existing facilities. Transmission facilities below 200 kV are not subject to competitive solicitation unless they span more than two participating transmission owner service territories or extend from the ISO balancing authority area to another balancing authority area.

If the approved transmission plan includes regional transmission facilities eligible for competitive solicitation, the ISO will commence Phase 3 by opening a window for the entities to submit applications to compete to build and own such facilities. The ISO will then evaluate the proposals and, if there are multiple qualified project sponsors seeking to finance, build, and own the same facilities, the ISO will select an approved project sponsor by comparatively evaluating all of the qualified project sponsors based on the tariff selection criteria. Where there is only one qualified project sponsor, the ISO will authorize that sponsor to move forward to project permitting and siting.

1.3.2 Interregional Transmission Coordination per FERC Order No. 1000

Following guiding principles largely developed through coordination activities, the ISO along with the other Western Planning Regions[29] participates in and advances interregional transmission coordination within the broader landscape of the Western Interconnection. These guiding principles were established to ensure that an annual exchange and coordination of planning data and information are is achieved in a manner consistent with expectations of FERC Order No. 1000. The guiding principles are documented in the ISO's Transmission Planning Business Practice Manual, as well as in comparable documents of the other Western Planning Regions.

The 2022-2023 transmission planning cycle was the first year of the two-year interregional coordination planning process that the ISO conducts with its neighboring planning regions WestConnect and Northern Grid. Accordingly, the Western Planning Regions initiated a new

[29] Western planning regions are the California ISO, NorthernGrid, and WestConnect.

biennial Interregional Transmission coordination cycle beginning in January 2022. The ISO hosted its submission period in the first quarter of 2022 in which proponents were able to request evaluation of an interregional transmission project. The submission period began on January 1 and closed March 31 with one interregional transmission project being submitted to the ISO. The Western Planning Regions held Interregional Coordination Meeting(s) on March 4, 2022, June 13, 2022, and March 9, 2023 to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[30] This process and results of the evaluation conducted with the other relevant planning regions, NorthernGrid and WestConnect, are set out in Chapter 5.

1.4 Other Influences

In addition to the key study plan inputs described above, the ISO must address a range of considerations in its planning process that shift in content and priority over the years to ensure overall safe, reliable, and efficient operation and develop effective solutions to emerging challenges.

This section discusses a number of the issues and other actions that the ISO took into account in preparing the 2022-2023 Plan.

1.4.1 SB 887, the Accelerating Renewable Energy Delivery Act

Senate Bill 887, the Accelerating Renewable Energy Delivery Act, was authored by Senator Josh Becker and signed into law by Governor Newsom on September 16, 2022. SB 887 provides state policy direction on a number of resource planning and transmission planning issues, including direction to the CPUC and CEC regarding inputs to be provided to the ISO in future planning cycles. The bill also provides direction about requests the CPUC is to make of the ISO in the process of conducting its FERC tariff-based planning processes in this and future planning cycles.

The ISO has considered the state policy direction provided by SB 887 in the development of this transmission plan and will incorporate the additional input from the CPUC and CEC in future planning cycles as it becomes available. The ISO has also addressed the specific request made by the CPUC to the ISO applicable to this 2022-2023 Plan as set out below.

1.4.1.1 CPUC Request to CAISO in Accordance with SB 887

The CPUC submitted a letter[31] to the ISO on January 13, 2023 in accordance with SB 887 indicating the following:

> *"Pursuant to Senate Bill 887 (Becker, 2022), this letter requests the California Independent System Operator to (1) identify, based as much as possible on studies and projections completed before January 1, 2023, by the CAISO, the CPUC and the California Energy Commission, the highest priority transmission facilities that are needed*

[30] Documents related to the 2018-2019 interregional transmission coordination meetings are available on the ISO website athttp://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

[31] http://www.caiso.com/InitiativeDocuments/Letter-2022-2023-Transmission-Planning-Process-Jan%2013,%202023.pdf

> *to allow for increased transmission capacity into local capacity areas to deliver renewable energy resources or zero-carbon resources that are expected to be developed by 2035, and (2) consider whether to approve such transmission projects as part of the CAISO's 2022–23 transmission planning process."*

The ISO has accordingly considered its past planning efforts, the 2022-2023 planning study results, and the policy direction applicable to this year's planning cycle. The results of this exercise are set out in Chapter 3, as the primary focus is associated with accessing renewable energy resources.

1.4.2 Non-Transmission Alternatives and Storage

Since implementing the current comprehensive transmission planning process in 2010, the ISO has considered and placed a great deal of emphasis on assessing non-transmission alternatives, including conventional generation, preferred resources (*e.g.*, energy efficiency, demand response, renewable generating resources), and market-based energy storage solutions as a means to meet local transmission system needs. As stated earlier, the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan but can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades and work with the relevant parties and agencies to seek their implementation. As the volumes of renewable generation and storage required to meet system needs have escalated rapidly in recent years, the challenge has shifted from seeking to support resources that may not otherwise develop, to testing the effectiveness of preferred resources to meeting the local needs and encouraging system capacity resources be procured in optimal locations.

The methodology used for assessing the effectiveness of local preferred resources is based on the initial methodology issued on September 4, 2013,[32] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[33] — energy efficiency, demand response, renewable generating resources, and energy storage — that was further advanced and refined through the development of the Moorpark Sub-area Local Capacity Alternative Study released on August 16, 2017.[34] Storage also played a major role in the consideration of preferred resource alternatives in LA Basin studies as well as the Oakland Clean Energy Initiative approved in the 2017-2018 Transmission Plan and modified in the 2018-2019 Plan. These efforts help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential alternatives to meeting identified needs.

In addition to providing opportunities for preferred resources including storage to be proposed in meeting needs that are being addressed within the year's transmission plan, each year's

[32] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013. http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

[33] To be precise, the term "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The ISO uses the term more generally here consistent with the preference for certain resources in lieu conventional generation.

[34] *See generally* CEC Docket No. 15-AFC-001, and *see* "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at: http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

transmission plan also identifies areas where future reinforcement may be necessary but immediate action is not required. The ISO has also expanded the scope of the biennial 10-year local capacity technical requirements study to provide additional information on the characteristics defining the need in the areas and sub-areas. The ISO expects developers interested in developing and proposing preferred resources as mitigations in the transmission planning process to take advantage of the additional opportunity to review those areas and highlight the potential benefits of preferred resource proposals in their submissions into utilities' procurement processes.

Once preferred resources – and storage in particular – have been identified as the preferred solution taking into account overall cost effectiveness and technical requirements, coordination with the CPUC – or other local regulatory authorities as the case may be – is needed to achieve the procurement of the resources.

The dispersion of procurement responsibility across a steadily increasing number of load-serving entities has increased the complexity and concerns regarding the efficacy of relying on market-based resources procured for system needs to be targeted in specific areas to also meet local needs. It appears the Central Procurement Entities (CPEs) may play a larger role in acquiring these resources. The ISO notes that in Decision (D.) 22-02-004, the CPUC directed one utility, in its role of Central Procurement Entity, to conduct a competitive solicitation process for a specific resource; the ISO sees this as a positive outcome in setting the direction for other needs in the future. Further, the CPEs can now contract with resources for 5 years or less that shall be deemed reasonable and preapproved if the certain conditions are met, and can contract for longer than 5 years subject to filing a Tier 3 Advice Letter for approval, as set out in CPUC Decision (D.) 22-03-034. The ISO is not aware of these provisions being used yet to acquire new resources required for transmission needs, however.

Accordingly, the ISO is continuing to follow its current approach to meet local needs with storage where possible, but is concerned with the progress made on resources being acquired to meet previously-identified needs.

Energy storage solutions can be a transmission resource or a non-transmission alternative (*e.g.*, market-based). The ISO has considered storage in both contexts in the transmission planning process, although market-based approaches have generally prevailed due to their ability to also participate in the electricity market.

Other Use-limited resources, including demand response:

The ISO continues to support integrating demand response, which includes bifurcating and clarifying the various programs and resources as either supply side or load-modifying. Activities such as participating in the CPUC's demand response-related proceedings support identifying the necessary operating characteristics that demand response should have to fulfill a role in meeting transmission system and local capacity needs.

In 2019, the ISO vetted the market processes it will use to dispatch slow demand response resources on a pre-contingency basis.[35] This work was founded on the analysis of the necessary characteristics for "slow response" demand response programs that was undertaken initially through special study work in the 2016-2017 Transmission Plan, which continued into 2017 through a joint stakeholder process with the CPUC.[36]

This work has helped guide the approach the ISO is taking in the more comprehensive study of local capacity areas in this planning cycle, examining both the load shapes and characteristics underpinning local capacity requirements, discussed earlier in this section.

1.4.3 System Modeling, Performance, and Assessments

The grid is being called upon to meet broader ranges of generating conditions and more frequent changes from one operating condition to another, as resources are committed and dispatched on a more frequent basis and with higher ramping rates and boundaries than in the past. This necessitates managing thermal, stability, and voltage limits constantly and across a broader range of operating conditions.

This has led to the need for greater accuracy in planning studies at the same time that challenged are compounded by the complexity of the settings in Inverter Based Resource models. The ISO's study work, built off the initial special study initiative undertaken in the 2016-2017 planning cycle, found and reaffirmed year after year the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. The ISO has made significant progress in establishing and implementing a more comprehensive framework for the collection of accurate generator model data through the process developed and set out in Section 10 of the ISO's Transmission Planning Process – Business Practice Manual. This established a schedule for validating models, and the ISO will be continuing with its efforts, in coordination with the Participating Transmission Owners, to collect this important information and ensure generation owners provide validated models.

1.5 ISO Processes coordinated with the Transmission Plan

The ISO coordinates the transmission planning process with several other ISO processes in addition to the generator interconnection procedures discussed above.

1.5.1 Distributed Generation (DG) Deliverability

The ISO developed a streamlined, annual process for providing resource adequacy (RA) deliverability status to distributed generation (DG) resources from transmission capacity in 2012 and implemented it in 2013. The ISO completed the first cycle of the new process in 2013 in

[35] Local Resource Adequacy with Availability-Limited Resources and Slow Demand Response Draft Final Proposal found here: http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-LocalResourceAdequacy-AvailabilityLimitedResources-SlowDemandResponse.pdf

[36] See "Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop," presentation, October 4, 2017.http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf

time to qualify additional distributed generation resources to provide RA capacity for the 2014 RA compliance year.

The ISO annually performs two sequential steps. The first step is a deliverability study, which the ISO performs within the context of the transmission planning process, to determine nodal MW quantities of deliverability status that can be assigned to DG resources. The second step is to apportion these quantities to utility distribution companies — including both the investor-owned and publicly-owned distribution utilities within the ISO-controlled grid — who then assign deliverability status, in accordance with ISO tariff provisions, to eligible distributed generation resources that are interconnected or in the process of interconnecting to their distribution facilities.

In the first step, during the transmission planning process the ISO performs a DG deliverability study to identify available transmission capacity at specific grid nodes to support deliverability status for distributed generation resources. This is done without requiring any additional delivery network upgrades to the ISO-controlled grid and without adversely affecting the deliverability status of existing generation resources or proposed generation in the interconnection queue. In constructing the network model for use in the DG deliverability study, the ISO models the existing transmission system, including new additions and upgrades approved in prior transmission planning process cycles, plus existing generation and certain new generation in the interconnection queue and associated upgrades. The DG deliverability study uses the nodal DG quantities specified in the base case resource portfolio that was adopted in the latest transmission planning process cycle to identify public policy-driven transmission needs. This is done both as a minimal target level for assessing DG deliverability at each network node and as a maximum amount that distribution utilities can use to assign deliverability status to generators in the current cycle. This ensures that the DG deliverability assessment aligns with the public policy objectives addressed in the current transmission planning process cycle. It also precludes the possibility of apportioning more DG deliverability in each cycle than was assumed in the base case resource portfolio used in the transmission planning process. As the amounts of distributed generation forecast in the recent renewable generation portfolios have declined from previous years, this creates less opportunity for this process to identify and allocate deliverability status to new resources. (Please refer to Chapter 3.)

In the second step, the ISO specifies how much of the identified DG deliverability at each node is available to the utility distribution companies that operate distribution facilities and interconnect distributed generation resources below that node. FERC's November 2012 order stipulated that FERC-jurisdictional entities must assign deliverability status to DG resources on a first-come, first-served basis, in accordance with the relevant interconnection queue. In compliance with this requirement, the ISO tariff specifies the process whereby investor-owned utility distribution companies must establish the first-come, first-served sequence for assigning deliverability status to eligible distributed generation resources.

Although the ISO performs this new DG deliverability process as part of and in alignment with the annual transmission planning process cycle, its only direct impact on the transmission planning process is adding the DG deliverability study to be performed in the latter part of Phase 2 of the transmission planning process.

1.5.2 Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[37] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution on this sensitive area — that additional measures should be taken to protect CEII information. Accordingly, the ISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the ISO's public website. Rather, this information can be accessed only through the ISO's market participant portal after the appropriate nondisclosure agreements are executed.

1.5.3 Planning Coordinator Footprint

The ISO provides planning coordinator services to Hetch Hetchy Water and Power, the Metropolitan Water District, the City of Santa Clara, and the California Department of Water Resources. Since the execution of the service agreements with these parties, the ISO has conducted the relevant study efforts to meet mandatory standards requirements for these entities within the framework of the annual transmission planning process. The ISO has met all requirements to fulfill its planning coordinator responsibilities for these entities in accordance with implementation schedules agreed upon with each entity.

The ISO had initially developed its interpretation of its planning authority/planning coordinator area in 2014 based on its operational control of its participating transmission owner assets, partly in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities, and documented its interpretation in a technical bulletin.[38]

Beginning in 2015, the ISO then reached out to several "adjacent systems" that are inside the ISO's balancing authority area and were confirmed transmission owners, but which did not appear to be registered as a planning coordinator. The ISO did this to determine whether these adjacent systems needed to have a planning coordinator and, if they did not have one, to offer to provide planning coordinator services to them through a fee-based planning coordinator services agreement. Unlike the requirements for the ISO's participating transmission owners who have placed their facilities under the ISO's operational control, the ISO is not responsible for planning and approving mitigations to identified reliability issues under the planning coordinator services agreement – but only for verifying that mitigations have been identified and that they address the identified reliability concerns. In essence, these services are provided to address mandatory standards via the planning coordinator services agreement, separate from and not part of the ISO's FERC-approved tariff governing transmission planning activities for facilities placed under ISO operational control. As such, the results are documented separately, and do not form part of this transmission plan.

In addition to the entities discussed above, the ISO is also providing planning coordinator services under a separate agreement to Southern California Edison for a subset of its facilities

[37] ISO tariff Section 20 addresses how the ISO shares Critical Energy Infrastructure Information (CEII) related to the transmission planning process with stakeholders who are eligible to receive such information. The tariff definition of CEII is consistent with FERC regulations at 18 C.F.R. Section 388.113, *et. seq*. According to the tariff, eligible stakeholders seeking access to CEII must sign a non-disclosure agreement and follow the other steps described on the ISO website.

[38] Technical Bulletin – "California ISO Planning Coordinator Area Definition" (created August 4, 2014, last revised July 28, 2016 to update URL for Appendix 2).

that are not under ISO operational control but which were found to be Bulk Electric System as defined by NERC.

Considering the entirety of the ISO-controlled grid, the ISO is not anticipating a need to offer these services to other parties, as the ISO is not aware of other systems inside the boundaries of the ISO's planning coordinator footprint requiring these services.

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Chapter 2

2 Reliability Assessment

2.1 Overview of the ISO Reliability Assessment

The ISO conducts its annual reliability assessment to identify facilities that demonstrate a potential of not meeting the applicable reliability performance requirements and identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards, Western Electricity Coordinating Council (WECC) regional criteria, and ISO transmission planning standards. These requirements are set out in Section B2.2 of Appendix B. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2022-2023 planning cycle, the ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable reliability standards. The ISO performed this analysis across a 10-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions.

This study is part of the annual transmission planning process and performed in accordance with Section 24 of the ISO tariff and as defined in the Business Process Manual (BPM) for the Transmission Planning Process.

The ISO annual reliability assessment is a comprehensive annual study that includes:

- Power flow studies;
- Transient stability analysis; and,
- Voltage stability studies.

The WECC full-loop power flow base cases provide the foundation for the study. The detailed assumptions, methodologies and reliability assessment results are provided in Appendix B and Appendix C.

In addition, the ISO has incorporated into this study process a review of short-circuit studies conducted by the transmission owners to identify and address proactively potential fault level issues affecting future resource additions.

2.1.1 Backbone (500 kV and selected 230 kV) System Assessment

Conventional and governor power flow and stability studies were performed for the backbone system assessment to evaluate system performance under normal conditions and following power system contingencies for voltage levels of 230 kV and above. The backbone transmission system studies cover the following areas:

- Northern California — Pacific Gas and Electric (PG&E) system; and
- Southern California — Southern California Edison (SCE) system and San Diego Gas and Electric (SDG&E) system.

2.1.2 Regional Area Assessments

Conventional and governor power flow studies were performed for the local area non-simultaneous assessments under normal system and contingency conditions for voltage levels 60 kV through 230 kV. The regional planning areas are within the PG&E, SCE, SDG&E, and Valley Electric Association (VEA) service territories and are listed below:

- PG&E Local Areas including:
  - Humboldt area,
  - North Coast and North Bay areas,
  - North Valley area,
  - Central Valley area,
  - Greater Bay area,
  - Greater Fresno area,
  - Kern Area, and
  - Central Coast and Los Padres areas.
- SCE local areas including:
  - Tehachapi and Big Creek Corridor,
  - North of Lugo area,
  - East of Lugo area,
  - Eastern area, and
  - Metro area.
- San Diego Gas Electric (SDG&E) local area; and
- Valley Electric Association (VEA) area.

2.2 Reliability Standards Compliance Criteria

The 2022-2023 transmission plan spans a 10-year planning horizon and, as stated earlier, was conducted to ensure the ISO-controlled grid is in compliance with NERC standards, WECC regional criteria, and ISO planning standards across the 2022-2031 planning horizon. Sections B1.2.1 through B1.2.4 in Appendix B describe how these planning standards were applied for the studies of the 2022-2023 transmission planning process.

2.3 Study Assumptions

In Phase 1 of the ISO annual transmission planning process, the ISO develops the Unified Planning Assumptions and Study Plan[39] for this planning cycle. The study assumptions and methodologies are included in Section B2.3 of Appendix B. The following sections summarize the study assumptions used for the reliability assessment.

2.3.1 Load and Resource Assumptions

The ISO's annual transmission planning process reliability assessment uses as inputs assumptions the California Energy Commission's (CEC) energy demand forecast and the California Public Utilities Commission's (CPUC) base portfolio developed through its integrated resource plan. As described in Section 1.2, the reliability analysis is based on the CEC's 2021 IEPR Additional Transportation Electrification Scenario[40] and the base portfolio provided to the ISO via Decision (D) 22-03-004[41] issued on February 15, 2022.

Table 2.3-1 provides the non-coincident load for each of the planning areas in the PG&E, SCE, SDG&E and VEA planning areas.

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39 http://www.caiso.com/InitiativeDocuments/FinalStudyPlan-2022-2023TransmissionPlanningProcess.pdf

40 The CEC adopted the 2021 IEPR Energy Demand Forecast, 2021-2035 on January 26, 2022 [https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1] The CEC subsequently adopted 2021 IEPR Additional Transportation Electrification Scenario that on July 1, 2022, the CEC and CPUC requested the ISO utilize in the 2022-2023 Transmission Plan. [http://www.caiso.com/InitiativeDocuments/2022-2023TransmissionPlanningProcess-PortfolioTransmittalLetter.pdf]

41 Decision 22-02-004 released on February 10, 2022 for the Decision Adopting 2021 Preferred System Plan, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF

Table 2.3-1: Non-Coincident Load Forecast for Planning Areas

PTO	Planning Area	2024	2027	2032	2035 (Sensitivity Study)
PG&E	Humboldt	122	127	161	181
	North Coast & North Bay	1481	1511	1817	2005
	North Valley	880	905	984	1027
	Central Valley	3855	3979	4554	4888
	Greater Bay Area	9028	9259	10754	11801
	Greater Fresno	3468	3566	3869	3942
	Kern	2106	2152	2252	2339
	Central Coast & Los Padres	1095	1412	1640	1782
SCE	Tehachapi and Big Creek Corridor	2274	2102	1913	2044
	North of Lugo area	981	981	1024	1059
	Eastern	5095	5127	5465	5642
	Main	24436	24797	25685	26218
SDG&E		4821	4985	5459	6340
VEA	VEA	167	174	188	

2.3.2 Study Horizon and Years

The studies that comply with TPL-001-5 were conducted for both the near-term[42] (2024-2027) and longer-term[43] (2028-2032) per the requirements of the reliability standards.

Within the identified near and longer term study horizons the ISO conducted detailed analysis on years 2024, 2027 and 2032. In addition, the ISO conducted a sensitivity study on the year 2035.

2.4 Reliability Studies

In Phase 2 of the annual transmission planning process the reliability assessment is conducted based upon the Unified Planning Assumptions and Study Plan that were developed as a part of Phase 1 of the planning process. The preliminary reliability results were posted on the ISO webpage and with this posting the Request Window opens for the participating transmission owner to submit potential alternatives to address identified reliability constraints by September 15 and for all other stakeholders to submit their potential mitigation alternatives by October 15. In addition, the ISO held a stakeholder meeting to present the reliability results and for the participating transmission owners to present the potential alternatives that they submitted into the Request Window. The Request Window submissions have been posted on the ISO Market Participant Portal and a list of the submissions are provided in Appendix D. The detailed reliability contingency analysis is provided in Appendix C.

The ISO then conducts its reliability assessment, including technical and economic evaluations of the alternatives identified by the ISO or by stakeholders, to select the most effective and

[42] System peak load for either year one or year two, and for year five as well as system off-peak load for one of the five years.
[43] System peak load conditions for one of the years and the rationale for why that year was selected.

efficient recommendation. Details of the reliability studies, request window submission assessments and mitigation assessments are provided in Appendix B.

2.5 Reliability-Projects Needed

The reliability-driven projects that have been identified as needed to mitigate reliability constraints Appendix C are presented below. The comprehensive and detailed technical and economic evaluation of the constraints and the alternatives the ISO considered in selecting the recommended reliability-driven projects are set out in Appendix B.

In total, the reliability assessment has identified 24 new reliability-driven projects required in this transmission planning cycle for a total estimated cost of $1.76 billion.

2.5.1 Management Approved Projects

The reliability-driven projects within this section were identified as being needed in the reliability assessment with an estimated cost of less than $50 million and were presented to stakeholders as being recommended for management approval at the November 17, 2022 stakeholder meeting. Based on comments received and no objection raised at the following ISO Board of Governors meeting on December 15, 2022, ISO Management approved the transmission projects and informed the respective participating transmission owners of those approvals.

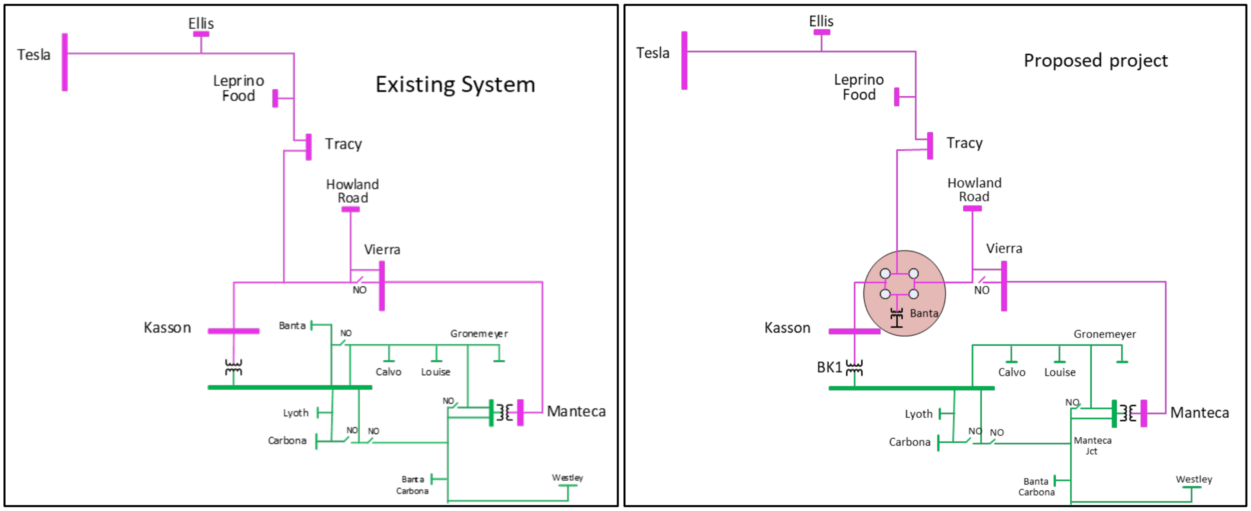
Banta Ring Bus Project

The reliability assessment of the PG&E Central Valley planning area in Section B3.3 of Appendix B identified contingencies (P1, P2 and P3) which resulted in overloads on the Vierra-Tracy-Kasson 115 kV line. The scope of the project to mitigate the identified constraints consists of the following:

- Convert existing Banta substation from 60 kV to 115 kV;
- Establish a 115 kV ring bus configuration to terminate the 115 kV lines from Kasson, Tracy and Vierra at the Banta 115 kV substation;
- Install a 115/12 kV 60 MVA transformer; and
- Re-terminate the 12 kV distribution feeders to the 12 kV bus at the new Banta 115 kV substation.

The estimated cost of the transmission component of this project is $9M to $17.5M and the expected in-service date is 2024. In the interim, the area will rely on operating action plans.

Figure 2.5-1: Banta Ring Bus Project



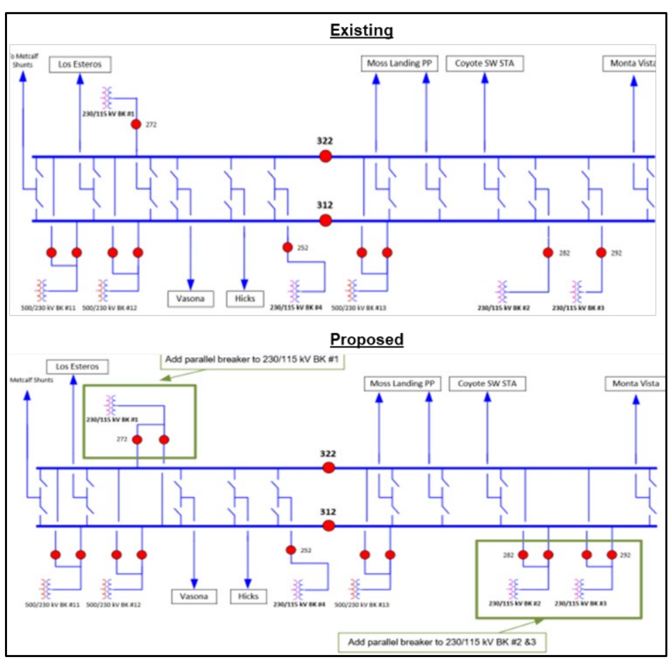
Metcalf 230/115 kV Transformers Circuit Breaker Addition

The reliability assessment of the PG&E Greater Bay planning area in Section B3.5 of Appendix B identified contingencies (P2 and P6) which resulted in overloads of the Metcalf 230/115 kV banks in both the near-term and long-term planning horizons of the assessment. The scope of the project to mitigate the identified constraints consists of the following:

- Adding parallel breakers to each of the 230/115 kV banks Nos. 1, 2, and 3 at Metcalf 230 kV Substation.

The estimated cost of this project is $7.5M to $15M and the in-service date is 2026. In the interim, the area will rely on operating action plans.

Figure 2.5-2: Metcalf 230/115 kV Transformers Circuit Breaker Addition Project



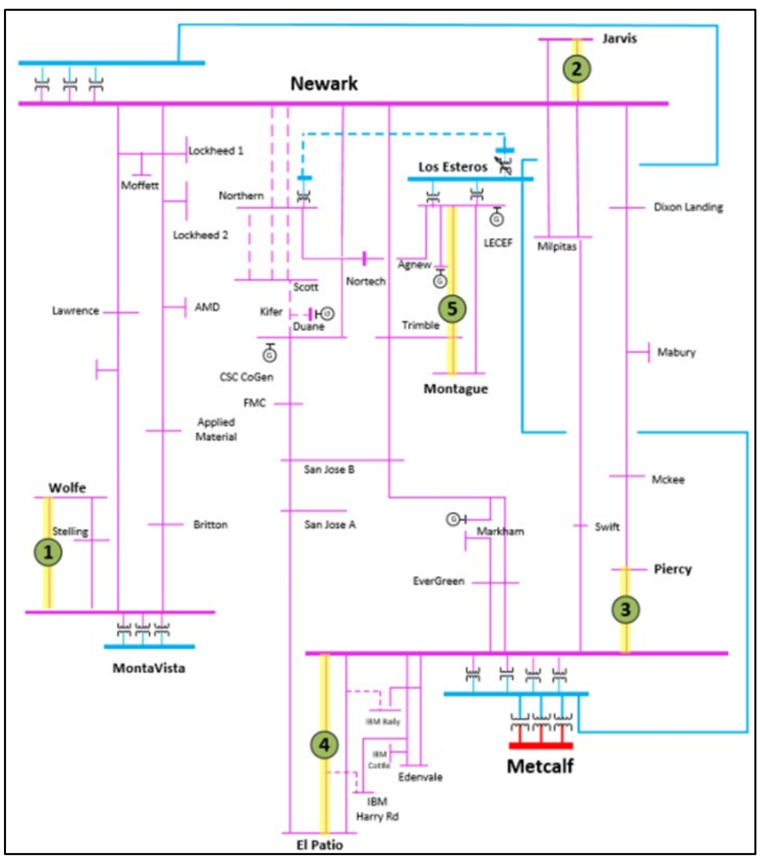
South Bay Area Limiting Elements Upgrade Project

The reliability assessment of the PG&E Greater Bay planning area in Section B3.5 of Appendix B identified contingencies (P1, P6 and P7) which resulted in overloads on 115 kV lines in South Bay Area due to limiting elements on the existing 115 kV lines in the area in both the near-term and longer-term planning horizons. The scope of the project to mitigate the identified constraints consists of the following:

- Monta Vista –Wolfe 115 kV Line (limiting element – terminal conductor);
- Newark –Jarvis #1 115 kV Line (limiting element – line switch);
- Metcalf-Piercy 115 kV Line (limiting element – terminal conductor);
- Metcalf-El Patio#1 115 kV Line (limiting element – terminal conductor); and
- Los Esteros-Montague 115 kV Line (limiting element – CB 132 & associated switches).

The estimated cost of this project is $5.5M to $11M and the in-service date is 2027. In the interim, the area will rely on operating action plans.

Figure 2.5-3: South Bay Area Limiting Elements Upgrade project one-line diagram



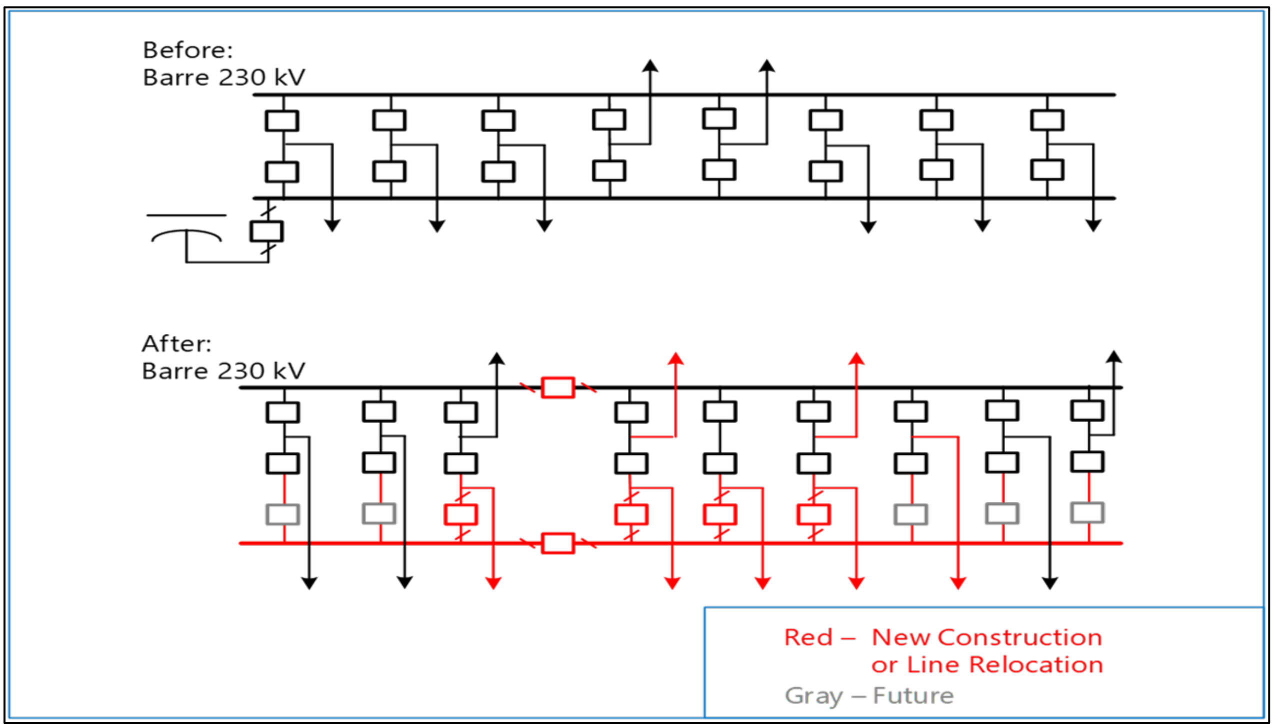
Barre 230 kV Switchrack Conversion to Breaker-and-a-Half Project

The project was submitted by SCE in the Request Window, as indicated in the SCE Main planning area in Section B5.4 of Appendix B, to mitigate short circuit duty issues driven by the extension of once-through-cooling units in the LA basin. The project converts Barre 230 kV switchrack to breaker-and-a-half configuration and split Barre 230 kV by adding bus sectionalizing circuit breakers. The project reduces the short circuit duty at Barre 230 kV well below the 63 kA existing capability to accommodate new generation and maintain safety. The scope of the project to mitigate the identified constraints consists of the following:

- Convert Barre 230 kV switchrack to breaker-and-a-half configuration by relocating the south bus and adding a third circuit breaker to four bay positions;
- Add sectionalizing circuit breakers and split the Barre 230 kV bus; and
- Relocate 230 kV lines, towers, and other facilities within substation.

The estimated cost of this project is $45 million with a targeted in-service date of 6/30/2026. The project scope includes the following:

Figure 2.5-4: Barre 230 kV Switchrack Conversion to Breaker-and-a-Half Project



Mira Loma 500 kV Circuit Breaker Upgrade Project

The project was submitted by SCE in the Request Window, as indicated in the SCE Main planning area in Section B5.4 of Appendix B, to address the short circuit duty concerns on four (4) 500 kV circuit breakers at Mira Loma 500/230 kV substation that are loaded to greater than 95% and 100% of the rated 50 KA short circuit duty capability in the near-term and the longer-term planning horizon. The scope of the project to mitigate the identified constraints consists of the following:

- Replace four 50 kA 500 kV circuit breakers at Mira Loma with new 63 kA rated circuit breakers.

The estimated cost of this project is $10 million with a targeted in-service date of 12/31/2026.

2.5.2 Projects Recommended for Approval

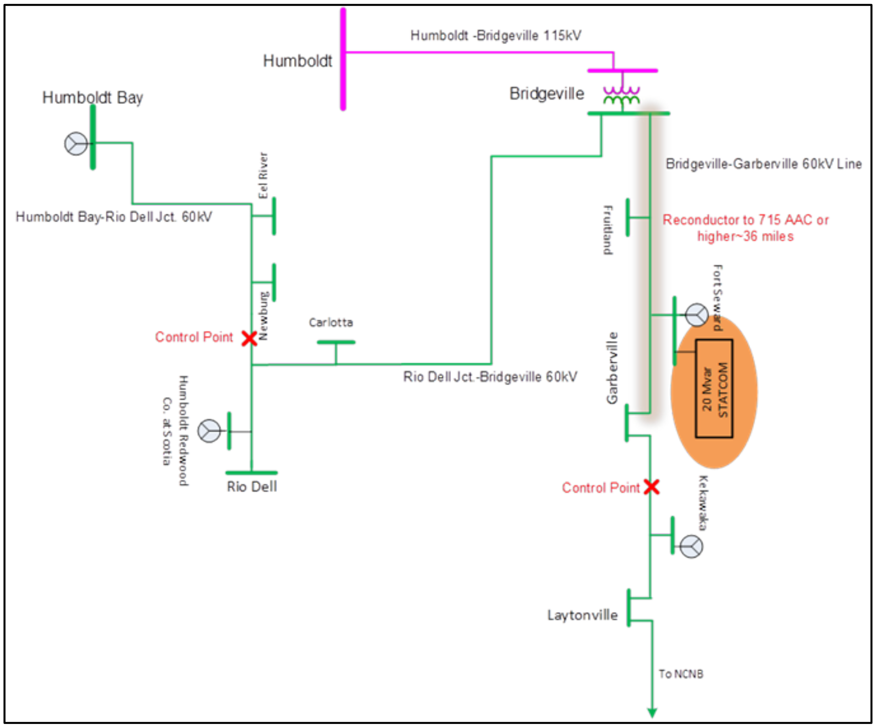
Garberville Area Reinforcement Project

The ISO is recommending approval of the Garberville Area Reinforcement Project. The reliability assessment of the PG&E Humboldt planning area in Section B3.1 of Appendix B identified contingencies (P1, P2, P3 and P6) in the near-term and long-term planning assessments that resulted in overloads and low voltages on the Humboldt 60 kV system. The scope of the project to mitigate the identified constraints consists of the following:

- Reconductoring of the entire Bridgeville-Garberville 60 kV line to achieve at least 631 Amps of summer normal rating (715 AAC conductor) which is about 36 circuit miles in length;
- Replacement of wood poles with LDSP will be required;
- Installation of a 20 MVAR STATCOM at Fort Seward 60 kV Substation;
- Establishing an operational control point to be able to open the line section from Garberville to Kekawaka 60 kV line; and
- Establishing an operational control point to be able to open the line section from Newburg to Rio Dell Jct. 60 kV line.

The estimated cost of this project is $102M to $204M and the expected in-service date is 2032. In the interim, the area will rely on operating action plans.

Figure 2.5-5: Garberville Area Reinforcement Project one-line diagram.



Expanded Scope of Tulucay-Napa #2 Line Capacity Increase Project

The ISO is recommending approval of expanding the scope of the previously approved Tulucay - Napa #2 60 kV Line Capacity Increase project in the ISO's 2019-2020 Transmission Plan. The reliability assessment of the PG&E North Coast and North Bay area in Section 3.2 of Appendix B identified contingencies (Categories P1 and P3) which resulted in overloads on the Tulucay - Napa #2 60 kV line starting in 2024. The previously approved Tulucay - Napa #2 60 kV Line Capacity Increase project that is expected to be in-service by the fourth quarter of 2025 will mitigate the overloads identified in 2027; however is not adequate to mitigate the overload observed by 2032. The original scope of the Tulucay - Napa #2 60 kV Line Capacity Increase project was as follows:

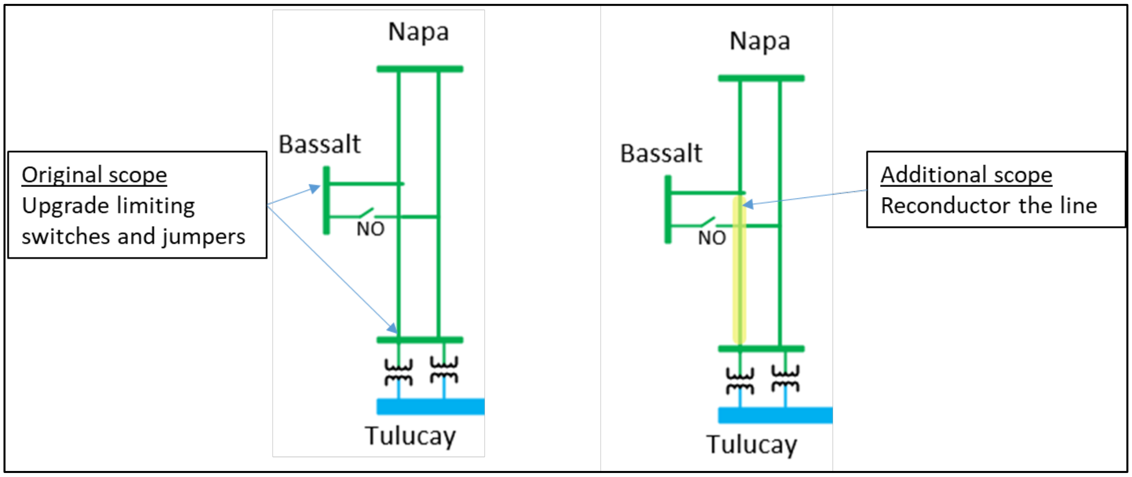
- Replace limiting switches and jumpers at Basalt and Tulucay 60 kV substations.

To mitigate the incremental constraints identified by the year 2032, the ISO is recommending to re-scope the previously approved project to include the following in the scope of the project:

- Reconductor the Tulucay-Napa #2 60 kV line from Tulucay to Basalt.

The estimated total cost of the original scope to replace limiting switches and jumpers at Basalt and Tulucay 60 kV substations and the expansion of the project to reconductor the Tulucay-Napa #2 60 kV line from Tulucay to Basalt was $5 to $10 million. The expected cost of the expansion of the project is $2.3 to 4.6 million, with a new total estimated cost of $7.3 to 14.6 million and the expected in-service date is 2028.

Figure 2.5-6: Reconductoring the Tulucay - Napa #2 60 kV (Tulucay 60 kV to Basalt 60 kV) line



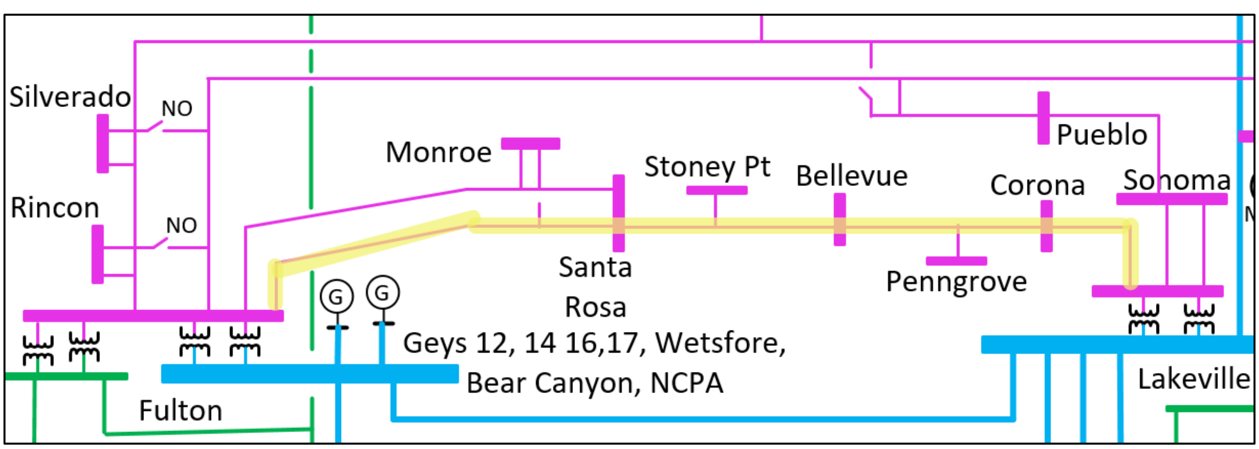
Reconductoring Santa Rosa Area 115 kV Lines Project

The ISO is recommending approval of the Reconductoring Santa Rosa Area 115 kV Lines project. The reliability assessment of the PG&E North Coast and North Bay area in Section B3.2 of Appendix B identified contingencies, Categories P2-4, P6 and P7, which resulted in overloads on the Corona-Lakeville 115 kV line, Santa Rosa-Corona 115 kV and Fulton-Santa Rosa No.1&2 115 kV lines starting in 2024. The scope of the project to mitigate the identified constraints consists of the following:

- Reconductoring the Fulton-Santa Rosa #1 and #2 115 kV lines;
- Reconductoring the Santa Rosa-Corona 115 kV line; and
- Reconductoring the Corona-Lakeville 115 kV lines.

The estimated cost of this project is $37M to $74M and the expected in-service date is 2028. In the interim, the area will rely on operating action plans.

Figure 2.5-7: Reconductoring Santa Rosa Area 115 kV Lines Project



The ISO also considered RAS, which turned out not feasible as the number of required elements (both contingency and overloaded facilities) to be monitored will exceed the maximum per the ISO Planning Standard.

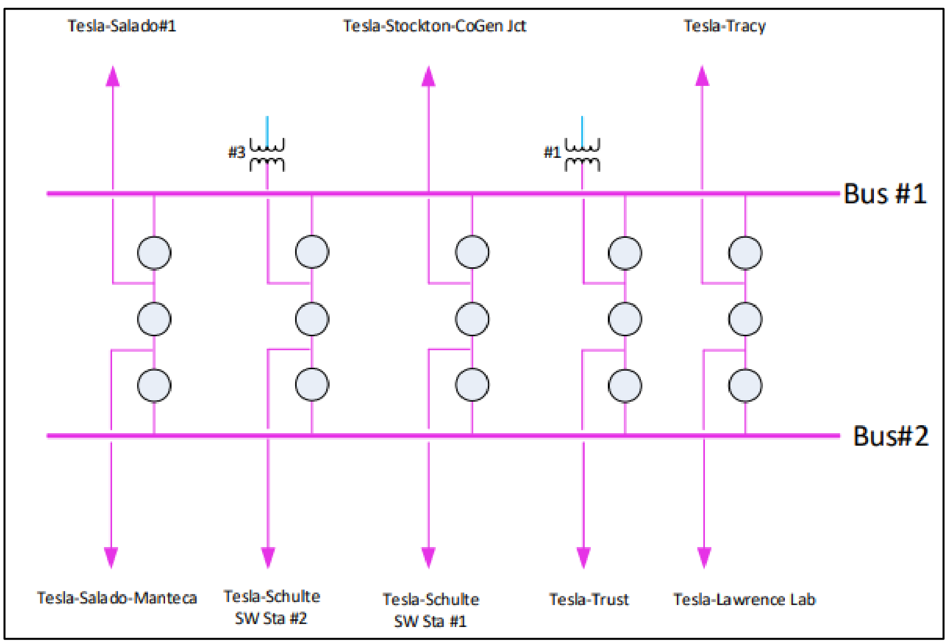
Tesla 115 kV Bus

The ISO is recommending approval of the Tesla 115 kV Bus Reconfiguration project. The reliability assessment of the PG&E Central Valley planning area in Section B3.3 of Appendix B identified contingencies, P2-4, at Tesla 115 kV substation resulting in overloads and voltage issues in the underlying 115 kV network in the area starting in the near-term. The scope of the project to mitigate the identified constraints consists of the following:

- Converting the current Tesla 115 kV substation from the current double bus single breaker configuration to a breaker-and-a-half configuration with folded bus design.

The estimated cost of this project is $27.5M to $55M and the expected in-service date is 2030. In the interim, the area will rely on operating action plans.

Figure 2.5-8 Recommended Breaker-and-a-Half Bus Configuration at Tesla 115 kV Substation



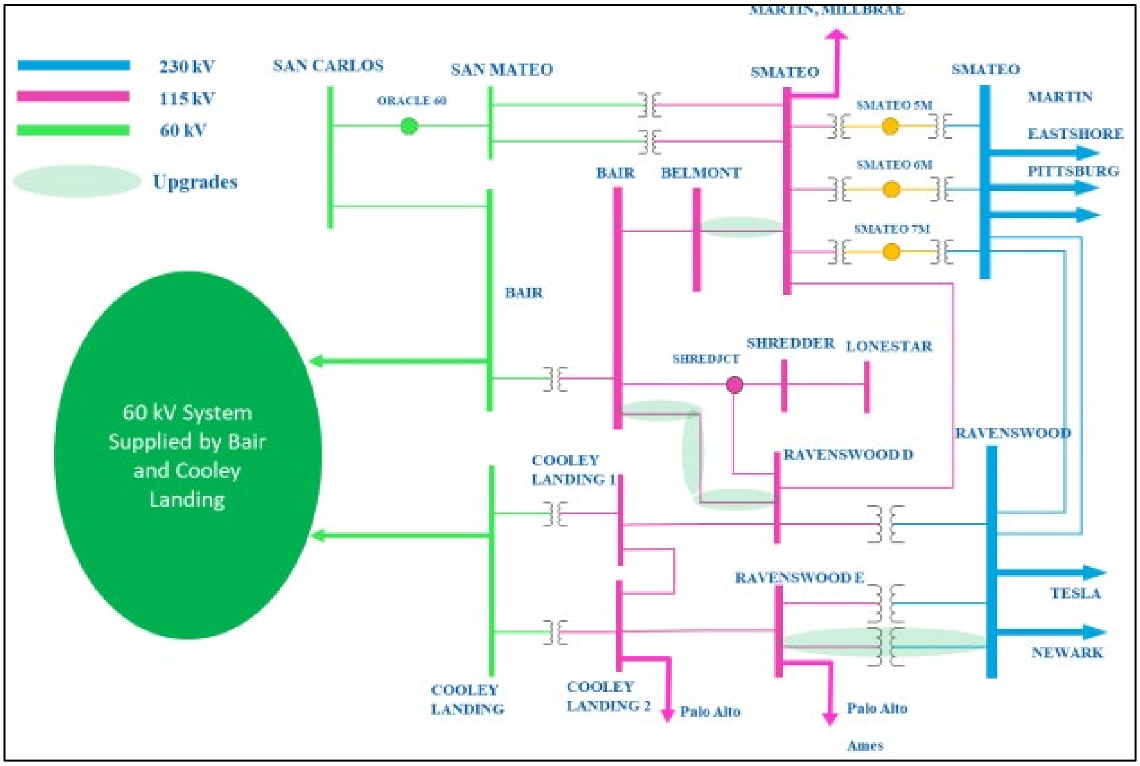
Redwood City Area 115 kV System Reinforcement Project

The ISO is recommending approval of the Redwood City Area 115 kV System Reinforcement project. The reliability assessment of the PG&E Greater Bay planning area in Section B3.5 of Appendix B identified contingencies (P6 and P7) which resulted in overloads on multiple 115 kV and 60 kV lines in Peninsula area in both the near-term and longer-term planning horizon. In addition, in the longer-term planning horizon only there were contingencies (P1, P3 and P6) which resulted in overloads on the Ravenswood 230/115 kV banks. The scope of the project to mitigate the identified constraints consists of the following:

- Reconductoring the San Mateo-Belmont and Ravenswood-Bair 115 kV lines; and
- Adding a new 230/115 kV transformer at the Ravenswood substation.

The estimated cost of this project is $55.4M to $110.8M and the in-service date is 2030. In the interim, the area will rely on operating action plans.

Figure 2.5-9: Figure – Redwood City Area 115 kV System Reinforcement project one-line diagram.



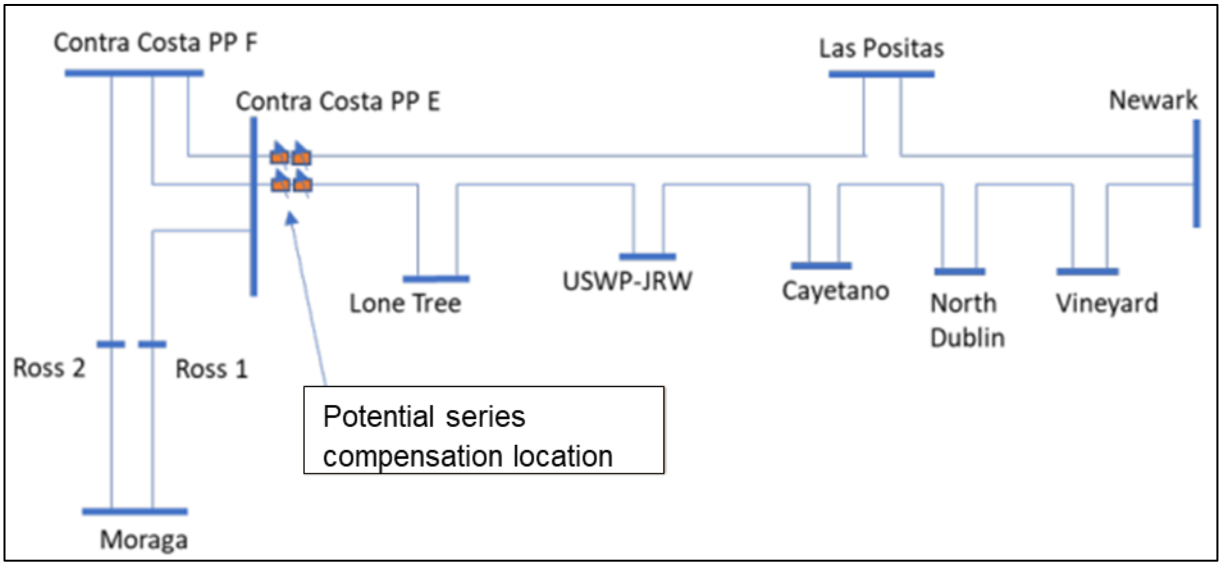
Lone Tree – Cayetano – Newark Corridor Series Compensation

The ISO is recommending approval of the “Lone Tree – Cayetano – Newark Corridor Series Compensation" project. The reliability assessment of the PG&E Greater Bay planning area in Section B3.5 of Appendix B identified contingencies (P2, P3, P6 and P7) which resulted in overloads were on the Contra Costa-Newark corridor 230 kV lines in both the near-term and longer-term planning horizons. The scope of the project to mitigate the identified constraints consists of the following:

- Installing 6 to 8 ohm series compensation (reactance) devices on the Cayetano-Lone Tree and Las Positas-Newark 230 kV lines. The series compensation would only require to be switched in under system conditions that could potentially overload the Cayetano-Lone Tree and Las Positas-Newark 230 kV lines.

The estimated cost of this project is $15M to $25M and the in-service date is 2027. In the interim, the area will rely on operating action plans.

Figure 2.5-10: Lone Tree – Cayetano – Newark Corridor Series Compensation Project



Los Banos 70 kV related issues

The ISO is recommending approval of the Los Banos 70 kV Area Reinforcement project. The existing Los Banos 70 kV area is served by two 230/70 kV transformers and a 115/70 kV transformer at Mendota. The reliability assessment of the PG&E Greater Fresno planning area in Section B3.6 of Appendix B identified contingencies (P1) which resulted in overloads on the underlying 70 kV lines and transformer, which includes the Los Banos 230/70 kV Transformer #3 and Los Banos-Canal-Oro Loma, Los Banos-Livingston Jct-Canal, Mercy Springs-Canal #1, Mercy Springs Sw Station-Oro Loma and Oro Loma-Mendota 70 kV lines. In addition, the overloads are increasing due to additional new distribution customer driven load increases at the Canal, Ortiga, Santa Nella and Wright 70 kV substations starting 2024 further requiring system upgrades to enhance reliability. The scope of the project to mitigate the identified constraints consists of the following:

- Install 230 kV partial bay at the new generation driven 230 kV switching station adjacent to Dos Amigos PP 230 kV Substation;[44]
- Add a new 70 kV Bus in the new generation driven 230 kV switching station, then it will be converted to a new 230/70 kV substation;
- Install one 230/70 kV transformer at the new 230/70 kV substation;
- Install a new 70 kV transmission line from new 70 kV Bus to Mercy Springs 70 kV Bus, and the new line is about one mile; and
- Install one breaker at Mercy Springs 70 kV Switching Station.

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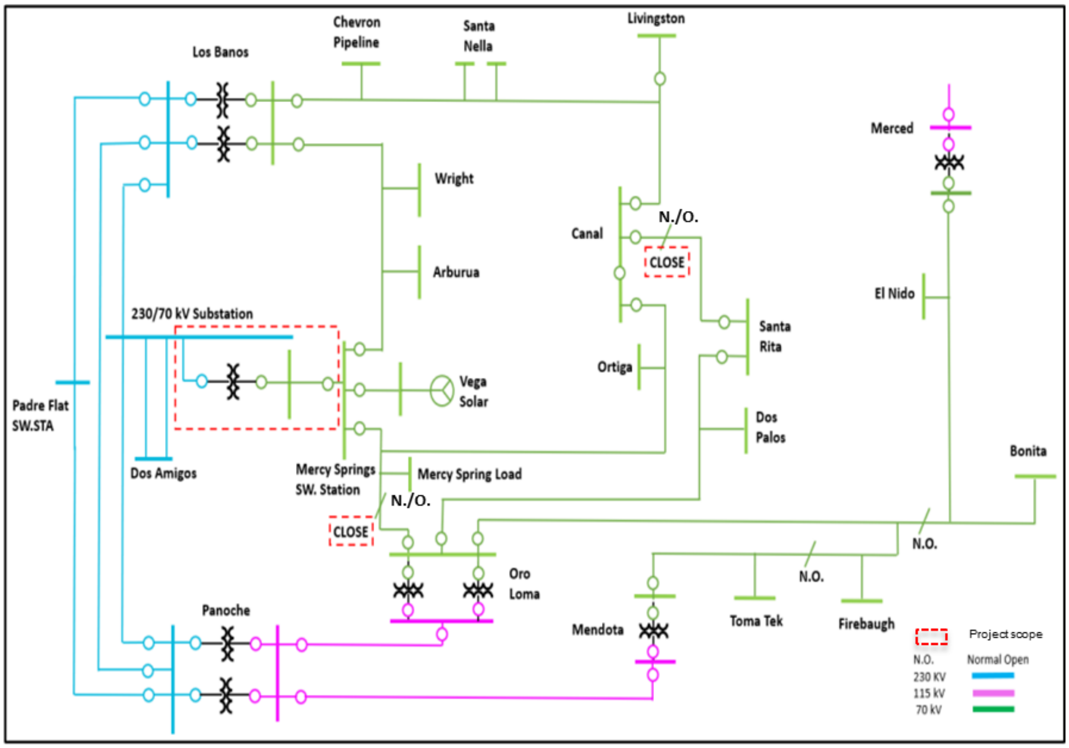
44 Network upgrade in PG&E area, ID 22rsmt-4 New 230 kV switching station to loop Dos Amigos – Panoche # 3 230 kV, with ih-service date of Q4-2028 from ISO January 25 quarterly Transmission Development forum. http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=2CC974D9-6145-438D-9EB5-B9A784549FA9

The total estimated cost of this project is $30M to $60M. The expected in-service date of this project is May 2029. In the interim, the area will rely on operating action plans.

Figure 2.5-11: Los Banos 70 kV Area Reinforcement Project



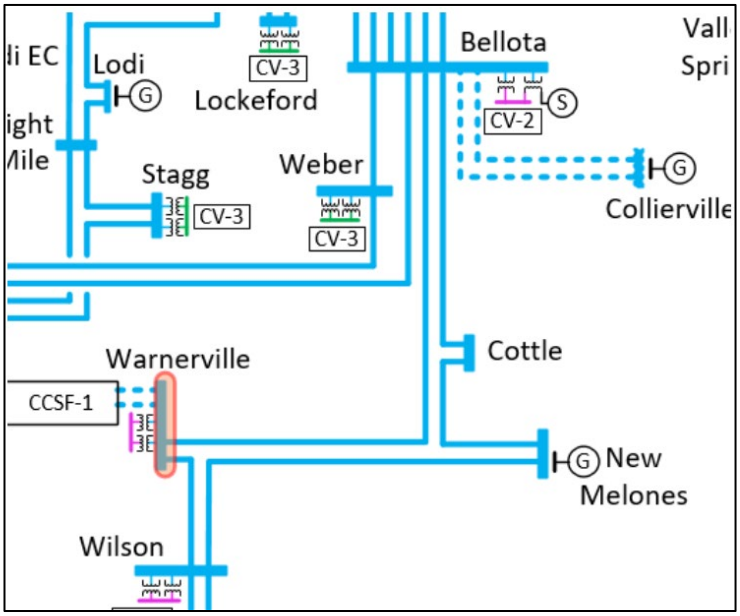
Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation as part of the previously approved Bellota-Warnerville 230 kV line reconductoring project

The Bellota-Warnerville 230 kV line reconductoring project was previously approved in the 2012-2013 transmission planning process. In the 2021-2022 transmission planning process, updated information was shared with the ISO that neighboring system equipment upgrades at Warnerville 230 kV substation, which is owned and operated by City and County of San Francisco (CCSF), are triggered by this previously approved project and that the rating of the Bellota-Warnerville 230 kV line following reconductoring will be limited by equipment at the Warnerville end. The ISO has voluntarily agreed, as set out in Section 24.10 of the ISO tariff, to the cost of the upgrades to limiting equipment. The incremental project scope that is being recommended for approval in this cycle includes the following:

- Upgrade limiting equipment at Warnerville 230 kV, which includes installing new jumpers, switches and new relays.

The total estimated cost of this incremental scope is $1.6M. The expected in-service date of this project is 2024.

Figure 2.5-12: Bellota-Warnerville 230 kV line reconductoring



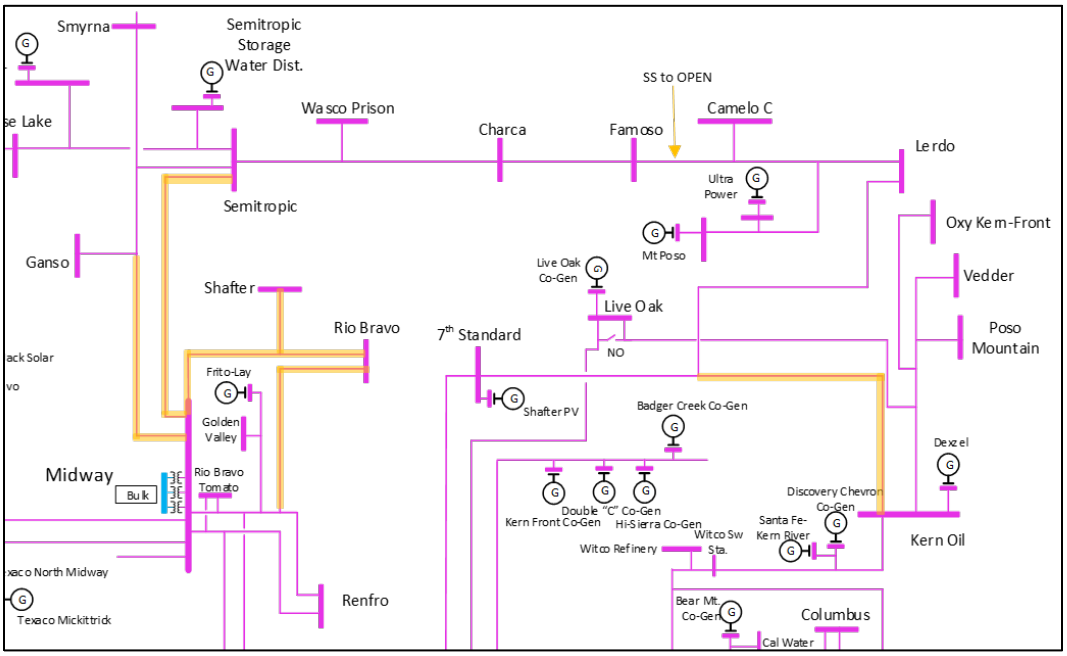
North East Kern 115 kV Line Reconductoring Project

The ISO is recommending approval of the North East Kern 115 kV Line Reconductoring project. The reliability assessment of the PG&E Kern planning area in Section 3.7 of Appendix B identified contingencies (P1 and P7) which resulted in multiple overloads in the 115 kV area around the Midway substation in both the near-term and longer-term planning horizon. The scope of the project to mitigate the identified constraints consists of the following:

- Reconductor ~13.6 circuit miles of Midway – Shafter 115 kV Line with a larger conductor to achieve at least 975 amps under summer emergency conditions;
- Reconductor ~8.3 circuit miles on the Shafter-Rio Bravo 115 kV with a larger conductor to achieve at least 975 amps under summer emergency conditions;
- Reconductor ~3.9 circuit miles on the Midway-Tupman-Rio Bravo-Renfro 115 kV (between Rio Bravo and Renfro Junction From 11/62 To Rio Bravo Sub) with a larger conductor to achieve at least 975 amps under summer emergency conditions;
- Reconductor ~3.5 circuit miles on the Lerdo-Kern Oil-7th Standard 115 kV Line (between Lerdo J and Kern Oil, from 023/005 To Kern Oil Sub) with a larger conductor to achieve at least 975 amps under summer emergency conditions;
- Reconductor ~6.8 circuit miles on the Smyrna-Semitropic-Midway 115 kV Line (between Midway and Ganso from Midway to 081/634 and from 081/634 to Ganso) with a larger conductor to achieve 1517 at least amps under summer emergency conditions;
- Reconductor ~14.1 circuit miles on the Semitropic-Midway #1 115 kV Line (between Midway and Semitropic_E) with a larger conductor to achieve at least 1517 amps under summer emergency conditions;

- Remove any limiting components as necessary to achieve full conductor capacity;
- Convert the existing control point to a summer setup to open line section from Wasco to McFarland 70 kV line; and
- Convert the existing control point to a summer setup to open line section from Famoso to Cawelo C 115 kV line.

Figure 2.5-13: Figure - North East Kern 115 kV Line Reconductoring Project



The estimated cost of this project is $128M to $256M and the in-service date is 2032. In the interim, the area will rely on operating action plans.

Several alternatives were assessed that included:

- Connecting Rio Bravo 115 kV to 7TH Standard 115 kV substation by using a portion of an idle line (Rio Bravo to Kern Oil 115 kV) and any necessary substation upgrades required in Rio Bravo and 7TH Standard 115 kV substations as well as building a new switching station at Shafter 115 kV junction.
    - This alternative was estimated at a similar cost $130M - $260M; however, it was not selected as it does not fully address all the constraints identified in planning assessment.
- Adding battery storage in the Shafter 115 kV area:
    - This alternative was not selected as it would also not address all the constraints identified in the planning assessment and there would be significant additional costs required to upgrade stations in the area for the interconnection of the battery storage, as well as concerns with deliverability of the battery within the area.

Coolwater 1A 230/115 kV Bank Project

The ISO is recommending approval of the Coolwater 1A 230/115 kV Bank Project project. The reliability assessment of the SCE North of Lugo planning area in Section 5.2 of Appendix B identified contingencies (P5 and P6) that resulted in low voltage and potential voltage collapse low voltages and potential voltage collapse at Coolwater, Dunn Siding, Baker, Tortilla and Tiefort 115 kV buses as well as high voltage at the locations under specific conditions in the near-term and longer-term planning horizons. The project will also provide operational flexibility, enhance reliability and retire the existing operating procedure which would radialize the system for a forced and scheduled outage in advance of the Category P6 contingencies. The Coolwater 1A 230/115 kV Bank Project will also allow a high speed rail project to energize with minimal delays as the bank is also needed for the retail load interconnection. The scope of the project to mitigate the identified constraints consists of the following:

- Adding a new 230/115 kV transformer bank at Coolwater.

The estimated cost for this project is $47 million. The proposed in-service date of the project is 12/31/2026. The ISO has identified the proposed reliability project as needed.

Control 115 kV Shunt Reactor Project

The ISO is recommending approval of the proposed Control 115 kV Shunt Reactor Project. The reliability assessment of the SCE North of Lugo planning area in Section 5.2 of Appendix B identified high voltage issues following P6 contingencies at Control and Inyo 115 kV buses. Based on the historical Inyo 230 kV bus voltage data, the Inyo and Control area has been experiencing normal high voltage issues in real time operation. The scope of the project to mitigate the identified constraints consists of the following:

- The project scope includes installing a 45 MVAR 115 kV shunt reactor at Control Substation.

The estimate cost of the project is $4 million. The proposed in-service date of the project is 12/31/2026.

Serrano 4AA 500/230 kV Transformer Bank Addition Project

The ISO is recommending approval of the Serrano 4AA 500/230 kV Transformer Bank Addition project. The reliability assessment of the SCE Main planning area in Section B5.4 of Appendix B identified contingencies (P6) which resulted in overloads of the remaining 500/230 kV transformer bank at Serrano substation in both the near-term and longer-term planning horizon. The scope of the project to mitigate the identified constraints consists of the following:

- Install a 4th 500/230 kV 1120/1344 MVA transformer bank at Serrano Substation; and
- Rebuild the 230 kV switching facility to 80 kA.

The estimated cost for this project is $120 million with a targeted in-service date of Q4 2027.

Sylmar Transformer Replacement Project

The ISO is recommending approval of the Sylmar Transformer Replacement project. The reliability assessment of the SCE Main planning area in Section B5.4 of Appendix B identified contingencies (P2, P4 and P6) which resulted in overloads on the SCE and LADWP joint-owned Sylmar 230/220 kV transformer banks E and F in the near-term and longer-term planning horizon. In addition, on November 26th, 2022, the LADWP-owned 230/220 kV Transformer Bank E at Sylmar substation suffered a failure. LADWP notified SCE that Bank E could not be repaired and would remain permanently inoperable. LADWP will replace the bank with increased capacity. SCE has also requested approval to replace (with increased capacity) the SCE-owned Bank F. The scope of the SCE project to mitigate the identified constraints consists of the following:

- Replace 230/220 kV transformer bank E at Sylmar substation with 1,290 MVA transformer.

The SCE estimated cost of the Bank F replacement is $23M.

Antelope-Whirlwind 500 kV Line Upgrade Project

The ISO is recommending approval of the Antelope-Whirlwind 500 kV Line Upgrade project. The reliability assessment of the SCE Main planning area in Section B5.7 of Appendix B identified contingencies (P2, P4, P5, and P6) which resulted in overloads of the Antelope-Whirlwind 500 kV line. The scope of the project is to mitigate the identified constraints consists of upgrading the Antelope – Whirlwind 500 kV line by increasing the ground clearance for nine (9) towers, which increases the normal and emergency line ratings by 32% and 27%. The estimated cost for this project is $4 to 6 million with an estimated in-service date of 2025.

Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Project

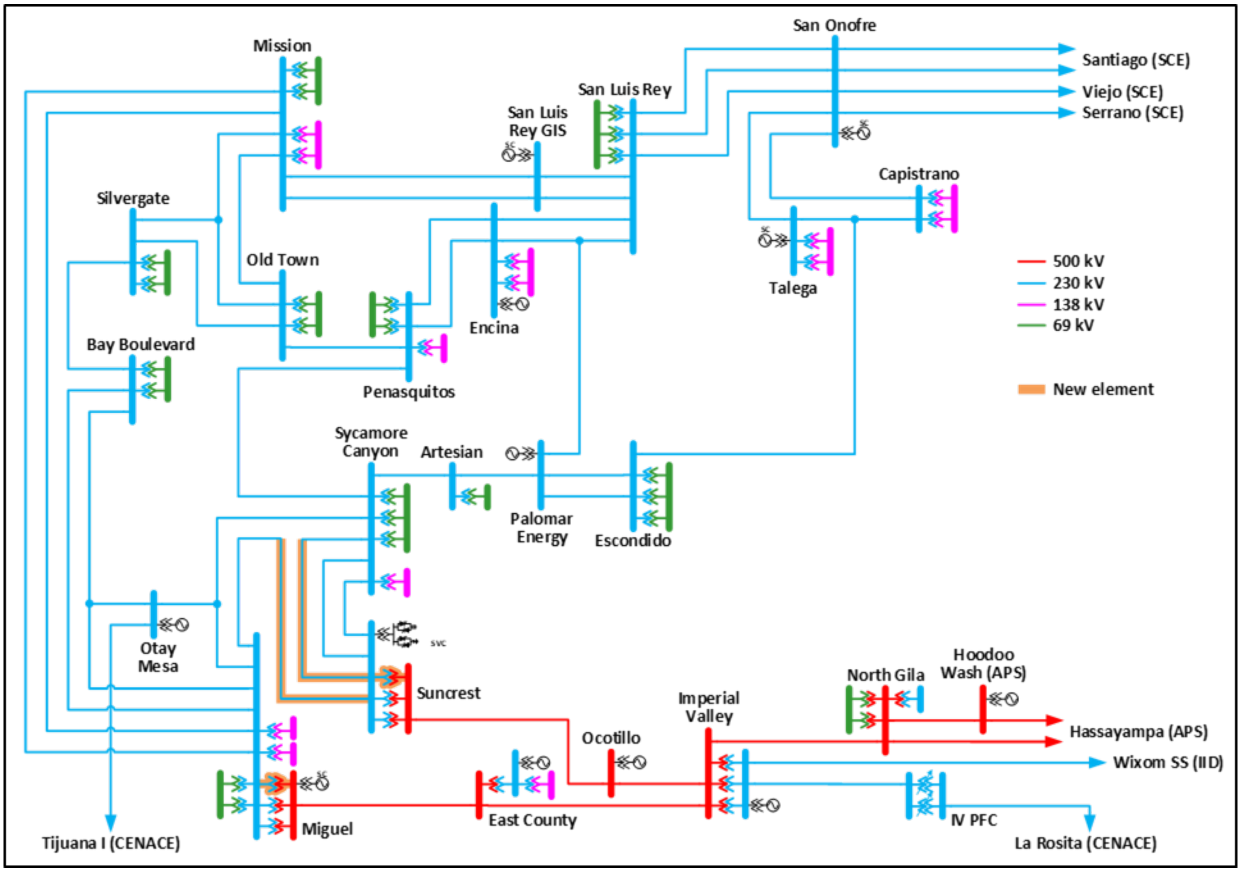
The ISO is recommending approval of the following project. The reliability assessment of the SDG&E planning area in Section B.6 of Appendix B identified contingencies (P3 and P6) in the near-term and long-term planning assessments that resulted in thermal overloads on the Suncrest – Sycamore Canyon 230 kV transmission lines and Suncrest and Miguel 500/230 kV banks. The scope of the project to mitigate the identified constraints consists of the following:

- A 16-mile double circuit 230 kV transmission line that will loop-in the existing TL23021 Miguel – Sycamore Canyon into Suncrest substation; and
- Install two new 500/230 kV banks at Suncrest and Miguel substations (one at each substation).

The estimated cost of this project is $275M to $375M and the expected in-service date is 2032.

In the interim, the area will continue relying on the existing RAS, 30-minute short-term emergency ratings and operational actions to mitigate the identified thermal overloads.

Figure 2.5-14: Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Project



PG&E Area Short Circuit Upgrade Projects

The following short-circuit upgrade projects were identified in PG&E's short circuit analysis as a part of this year's planning cycle including previously approved projects (i.e. Manning and Collinsville Substation project's) and the resources in the CPUC base portfolio.

Pittsburg 115 kV Bus Reactor

The analysis identified thirteen 230 kV circuit breakers at Pittsburg substation to be overstressed. The overstress is caused by the addition of the new Collinsville substation and contributions by the portfolio resources. The scope of the Pittsburg 115 kV Bus Reactor project is as follows:

- Six 18-ohm 3,000 Amp reactors;
- One spare reactor unit; and
- Associated switches and bus work.

The ISO is recommending approval of the Pittsburg 115 kV Bus Reactor project as an addition to the previously approved Collinsville 500/230 kV substation policy project. The estimated cost of this project is $13 million to $26 million. This additional scope is to be completed concurrently with the implementation of the new Collinsville substation.

Los Banos 230 kV Circuit Breaker Replacement

The analysis identified four 230 kV circuit breakers at Los Banos substation to be overstressed in the 2032 scenario. The overstress is caused by the portfolio resources. The scope of the Los Banos 230 kV Circuit Breaker Overstress project is as follows:

- Breaker 212, 222: Replace in place with new SMP Relays. May replace foundations/structures as needed; and
- Breaker 252, 262: Replace with two (2) new breaker-and-a-half bays in the new breaker-and-a-half bus section to meet the ultimate plan. T-Line relocations into new breaker-and-a-half positions.

The estimated cost of this project is $33 million to $66 million and the in-service date is 2032.

Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade

The analysis identified four 115 kV circuit breakers and thirteen 230 kV circuit breakers at Panoche substation to be overstressed. The overstress is caused by addition of the new Manning substation and contributions by the portfolio resources. The scope of the Panoche 115 kV and 230 kV Circuit Breaker Overstress project is as follows:

- Replace the 115 kV circuit breakers 132, 152, 102 and 162;
- Install a new MPAC building for the 115 kV bus section; and
- Convert 230 kV Bus Section D to breaker-and-a-half and replace overstressed breakers in Bus E to 63 kA at Panoche substation.

The ISO is recommending approval of the Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project as an addition to the previously approved Manning 500/230 kV substation policy project. The estimated cost of four 115 kV circuit breakers replacement is $22 million to $44 million and the cost for the 230 kV bus upgrade is $70 million to $140 million. The total estimated cost of the Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project is $92 to 184 million. This additional scope is to be completed concurrently with the implementation of the new Manning substation.

2.5.3 Previously Approved Projects on Hold

Moraga- Sobrante 115 kV Line Reconductor Project

The ISO recommends the Moraga-Sobrante remain on hold for this planning cycle. The reliability assessment of the PG&E Greater Bay planning area in Section 3.5 of Appendix B identified contingencies (P2 and P5) which resulted in overloads on the Moraga-Sobrante 115 kV line only in the longer-term planning horizon and a contingency (P6) which resulted in an overload only in the 2035 ATE sensitivity scenario. The ISO will continue to assess the need in future planning cycles.

North of Mesa Upgrades

The North of Mesa project was originally approved as the Midway-Andrew 230 kV project in the 2012-2013 Transmission Plan. The Midway-Andrew 230 kV project was split into two separate projects in the 2018-2019 Transmission Plan, with the South of Mesa Upgrades approved to proceed while the North of Mesa was placed on hold for further assessments in future planning cycles. In the 2020-2021 Transmission Plan, the ISO recommended as a mitigation procuring a 50 MW 4 hour battery storage at the Mesa 115 kV substation to address ISO Planning Standard maintenance requirements and utilizing existing Mesa, Divide and Santa Maria UVLS for peak load conditions, instead of proceeding with the North of Mesa upgrade. The ISO also recommended the North of Mesa upgrade project remain on hold pending procurement of the battery storage. Regarding battery storage procurement at Mesa 115 kV, on December 29, 2022, PG&E reported its progress on energy storage procurement at the Mesa 115 kV substation in compliance with Decision 22-02-004[45] to the CPUC, stating that no storage project has been procured by PG&E as part of its procurement requirements adopted in D.21- 06-035 that meets the operational requirements identified in the 2020-2021 TPP at the 115 kV bus of the Mesa substation.

In this cycle PG&E has proposed to change the Point of Interconnection (POI) of the battery storage from the 115 kV to the 230 kV at the Mesa substation due to the complications associated with the 115 kV interconnection. As part of this change in the POI, PG&E proposed to address the maintenance issue related to the Mesa 230/115 kV transformers by installing a system spare transformer. The estimated cost to install the system spare transformer is $12 million to $24 million. The new spare 230/115 kV transformer at the Mesa substation in combination with the battery storage at the Mesa 230 kV bus is the most cost effective solution for the identified maintenance issue in the Mesa area. As such, the ISO concurs with PG&E proposed change of battery storage POI to the Mesa 230 kV bus and recommends approval for installation of the system spare transformer.

The ISO recommends canceling the North of Mesa project. As a portion of the mitigation plan to address maintenance planning requirements, the ISO recommends changing the interconnection location of the 50 MW procured storage solution from the 115 kV bus to the 230 kV at the Mesa substation. The ISO also recommends approval of the Mesa Spare Transformer Installation project with an estimated cost of $12 million to $24 million.

Wheeler Ridge Junction Project

The ISO is recommending that the previously approved Wheeler Ridge Junction project be taken off hold and proceed with a scope modification described below. The reliability assessment of the PG&E Kern planning area in Section 3.7 of Appendix B identified contingencies (P1, P2, and P6) resulted in overloads on the Midway-Wheeler Ridge #1 and #2 230 kV lines. In addition to increasing load and commercial interest in this area for new generation, the Wheeler Ridge junction project with a revised scope is being recommended to

[45] ELEC_6804-E.pdf (pge.com)

be reinstated. This project will also address the issues identified in the Lamont 115 kV pocket. In the 2020-2021 transmission planning process, the ISO recommended procurement of a 95 MW 4-hour energy storage option to mitigate the 115 kV issues on the Kern-Lamont 115 kV system. In regards to the battery storage procurement at Lamont 115 kV, on December 28, 2022, PG&E submitted progress on energy storage procurement on the Kern-Lamont 115 kV system in compliance with Decision 22-02-004[46] to the CPUC, stating that no viable offers remain and that the PG&E CPE closed the Kern-Lamont RFO. With the Wheeler Ridge Junction project reinstated, the previously recommended procurement of a 95 MW 4-hour energy storage is no longer required for mitigation of reliability issues identified in the Kern-Lamont 115 kV system.

The scope of the Wheeler Ridge Junction project remains consistent with what was originally proposed with the exception of removing the following:

- Reconductor and upgrade 6 miles of the idle line from Wheeler Ridge Junction towards Magunden substation. Upgrade for 115 kV operation, and terminate at Magunden and WRJ stations.

Therefore the updated scope of the project is as follows:

- Build new 230/115 kV transmission substation at Wheeler Ridge Junction (WRJ) with:
    - 2.5 – 230 kV Breaker-and-a Half (ultimate 7),
    - 2.5 – 115 kV Breaker-and-a Half (ultimate 7), and
    - 2 – 230/115 kV 420 MVA transformers;
- Convert 14.5 miles of the Adobe Switching Station #1 Tap 115 kV line from Adobe Switching Station to tower 011/065 to 230 kV operation:
- Extend the newly converted 230 kV line the remaining 1.25 miles to Wheeler Ridge substation;
- Terminate the newly converted 230 kV circuit at Wheeler Ridge;
- Open end Kern-Tevis-Stockdale-Lamont 115 kV line at tower 005/035 and loop Stockdale 115 kV substation;
- Convert/Re-conductor 5 miles of the Kern-Tevis-Stockdale-Lamont 115 kV lines section from Towers 005/035 to 011/065 to 230 kV operation on both sides of double circuit tower line;
- Terminate both circuits at the WRJ station. Terminate both remaining 115 kV lines to Lamont at WRJ station;
- Remove Kern PP-Stockdale #2 230 kV line from Stockdale substation, and terminate the first newly converted 230 kV circuit. Bypassing Stockdale substation, creating the Kern-WRJ 230 kV Line;

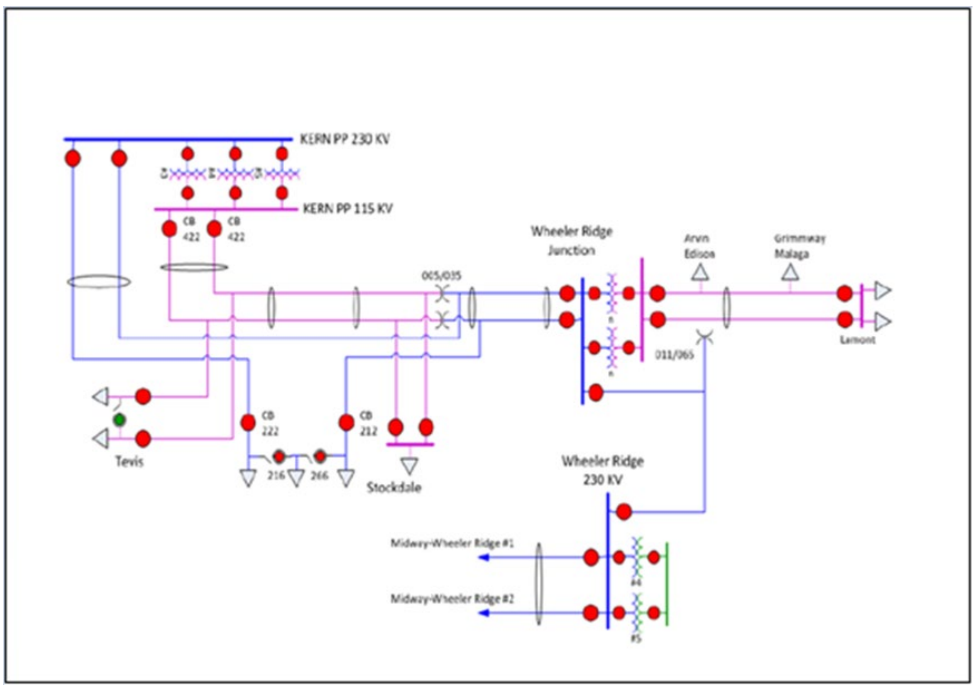
[46] ELEC_6801-E.pdf (pge.com)

- Terminate second newly converted 230 kV circuit at Stockdale substation, for a loop arrangement;
- Reconductor 6 miles of the Kern PP-Stockdale #1 and #2 230 kV lines; and
- Upgrade Stockdale 230 kV bus equipment as necessary to allow loop operation.

The previously approved project with the scope change is estimated to cost $259-517M and estimated tp take 8-10 years to complete. After completion of the project the P1 RAS at Bitterwater 230 kV will be converted to a P6/P7 RAS and continue to be utilized as mitigation for P6 and P7 overloads that could still occur.

Several Alternatives were considered including three additional 230 kV options and three 500 kV options. These options were not recommended due to feasibility concerns, cost, or concerns with both feasibility and cost.

Figure 2.5-15: Wheeler Ridge Junction Project



2.5.4 Projects under Review for Potential Approval in 2022-2023 Transmission Planning Process

Eldorado Short Circuit Duty Project

The ISO has identified a need for the Eldorado Short Circuit Duty project in the reliability assessment of the SCE Bulk System planning area in Section B5 of Appendix B. The short circuit studies conducted by SCE identified overstressed 230 kV and 500 kV breakers at Eldorado Substation. The existing Eldorado 230 kV and 500 kV breakers have a short circuit duty rating of 63kA. The short circuit duty assessment identified that with all active queued projects (generation and transmission) from SCE, NV Energy and LADWP modeled, including the approved GLW Upgrade project, the Eldorado jointly owned 230 kV bus SCD could reach 74.2 kA and the Eldorado 500 kV bus SCD could reach 68.9 kA. To address this identified issue the ISO has requested a mitigation plan from SCE. However, SCE's analysis is still ongoing. The ISO expects that the mitigation plan, in coordination with SCE, will be completed in the May 2023 time frame and will be evaluated for approval as a part of this planning cycle at a later date.

2.6 Conclusion

The 24 new reliability-driven projects are required in this transmission planning cycle for a total estimated cost of $1.76 billion are listed below. Table 3.0-1 includes the six projects that were approved by ISO management in this planning cycle for an estimated total cost of $100.1 million. Table 3.0-2 lists the 18 projects recommended for approval in this planning cycle for an estimated total cost of $1.66 billion.

Table 2.6-1: Management Approved Transmission Projects

Project Name	PTO Area	Planning Area	Cost ($M)	
			Low ($M)	High ($M)
Banta ring bus	PG&E	Central Valley	9.0	17.5
Metcalf 230/115 kV Transformers Circuit Breaker Addition	PG&E	Greater Bay Area	7.5	15.0
South Bay Area Limiting Elements Upgrade	PG&E	Greater Bay Area	5.5	11.0
Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation	PG&E	Greater Fresno	1.6	1.6
Barre 230 kV Switchrack Conversion to Breaker-and-a-Half	SCE	Main	45	45
Mira Loma 500 kV Circuit Breaker Upgrade	SCE	Main	10	10
		Total	**78.6**	**100.1**

Table 2.6-2 Recommended Transmission Projects for Approval

Project Name	PTO Area	Planning Area	Cost ($M)	
Garberville area reinforcement project	PG&E	Humboldt	102.0	204.0
Tulucay-Napa #2 60 kV line resonductoring project	PG&E	North Coast & North Bay	2.3	4.6
Santa Rosa 115 kV lines reconductoring project	PG&E	North Coast & North Bay	37.0	74.0
Tesla 115 kV Bus Reconfiguration Project	PG&E	Central Valley	27.5	55.0
Lone Tree – Cayetano – Newark Corridor Series Compensation	PG&E	Greater Bay Area	15.0	25.0
Los Banos 70 kV Area Reinforcement Project	PG&E	Fresno	30.0	60.0
Redwood City Area 115 kV System Reinforcement	PG&E	Greater Bay Area	55.4	110.8
Pittsburg 115 kV Bus Reactor project	PG&E	Greater Bay Area	13	26
Los Banos 230 kV Circuit Breaker Replacement	PG&E	Fresno	33	66
Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	Fresno	92	184
North East Kern 115 kV Line Reconductoring Project	PG&E	Kern	128.0	256.0
Mesa Spare Transformer Installation	PG&E	Central Coast & Los Padres	12	24
Coolwater 1A 230/115 kV Bank Project	SCE	North of Lugo	47	47
Control 115 kV Shunt Reactor	SCE	North of Lugo	4	4
Serrano 4AA 500/230 kV Transformer Bank Addition	SCE	Main	120	120
Sylmar Transformer Replacement	SCE	Main	23	23
Antelope-Whirlwind 500 kV Line Upgrade Project	SCE	Main	4	6
Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Projec	SDG&E	SDG&E	275	375
		Total	1,020.2	1,664.4

Three previously approved transmission projects were on hold pending further assessment. Based on this reliability assessment, the ISO recommends the following:

- Keep the Moraga- Sobrante 115 kV Line Reconductor project on hold;
- Cancel the North of Mesa project. Relocate the previously recommended procured storage at Mesa substation from the 115 kV bus to the 230 kV bus, and approve the Mesa Spare Transformer project; and
- Remove from being on hold and proceed with the Wheeler Ridge Junction project with a minor scope modification.

The ISO has identified the need for the Eldorado Short Circuit Duty project; however, this requires further assessment and coordination with SCE before the project can be recommended for approval. The ISO expects that the mitigation plan, in coordination with SCE, will be completed in the May 2023 timeframe and will be evaluated for approval at a later date.

Chapter 3

3 Policy-Driven Need Assessment

3.1 Background

The overarching public policy objective for the California ISO's Policy-Driven Need Assessment is the state's mandate for meeting renewable energy and greenhouse gas (GHG) reduction targets while maintaining reliability. For purposes of the transmission planning process, this high-level objective is comprised of two sub-objectives: first, to support Resource Adequacy (RA) deliverability status for the renewable generation and energy storage resources identified in the portfolio as requiring that status, and second, to support the economic delivery of renewable energy during all hours of the year.

The more coordinated and proactive approach taken in the ISO's current annual transmission planning process is part of a larger set of interrelated and coordinated planning and resource development activities being undertaken between the state energy agencies and the ISO. The ISO, for example, relies in particular on the CPUC for its lead role in developing resource forecasts for the 10-year planning horizon, with both the ISO and CEC providing input to the CPUC for those resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements and the MOU signed by the three parties in December 2022 reaffirms our respective roles and commitment to ensure we are working in concert with one another. As such, the MOU also sets the overall strategic direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement so the three entities are synchronized in working for the timely integration of new resources.

The CPUC issued Decision 22-02-004[47] on February 15, 2022 to transmit a portfolio based on the 38-million metric ton (MMT) greenhouse gas (GHG) target by 2030 and the 2020 Integrated Energy Policy Report demand forecast utilizing the high electric vehicle assumptions as the reliability and policy-driven base portfolio in the ISO 2022-2023 Transmission Planning Process (TPP). The portfolio includes a 2032 GHG target of 35 MMT, consistent with the 10-year timeline of the portfolio. The Decision is accompanied by Attachment A,[48] which provides the methodology and results of the resources-to-busbar mapping[49] process as well as other assumptions for use in the ISO TPP. This detailed information, establishing resource types and locations, is pivotal to the zonal approach to transmission planning, and the use of that zonal approach to shape and guide interconnection and resource procurement processes.

Decision 22-02-004 also delegated to the CPUC's Energy Division staff the development of a policy-driven sensitivity portfolio and associated busbar mapping based on a 30-million metric ton greenhouse gas target in consultation with staff of the California Energy Commission (CEC)

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[47] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF

[48] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF

[49] The busbar is the electrical connection within the ISO planning models where the generator is connected to the electrical system.

and ISO. Accordingly, the 2022-23 TPP High Electrification Sensitivity Portfolio was developed and transmitted to the ISO on July 1, 2022. In the transmittal letter,[50] the CPUC and CEC requested the ISO to:

- Use the 2021 Integrated Energy Policy Report (IEPR) Additional Transportation Electrification scenario as its load assumptions for 2022-2023 Transmission Planning Process (TPP) base and sensitivity case studies;
- Study the 30-million metric ton (MMT) High Electrification policy-driven sensitivity portfolio transmitted as the 2022-23 TPP High Electrification Sensitivity Scenario; and
- Continue studying the deliverability needs and corresponding transmission needs related to out-of-CAISO long-lead time resources, such as out-of-state wind and geothermal resources beyond the CAISO's balancing authority area. The letter further requested the ISO to assess the deliverability needs of these long lead-time resources while preserving the existing transmission capacity that has been allocated to other projects earlier in the queue.

3.2 Objectives of policy-driven assessment

Key objectives of the policy-driven assessment are to:

- Assess the transmission impacts of portfolio resources using:
  - Reliability assessment,
  - Peak and Off-peak deliverability assessment, and
  - Production cost simulation;
- Identify transmission upgrades or other solutions needed to ensure reliability, deliverability or alleviate excessive curtailment;
- Gain further insights to inform future portfolio development; and
- Set out the zonal capacities that are being established through coordinated transmission planning and resource planning, to shape and guide interconnection and resource procurement.

[50] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/tpp-portfolio-transmittal-letter.pdf

3.3 Study methodology and components

The policy assessment is geared towards capturing the impact of resource build-out on transmission infrastructure, identifying any required upgrades, and generating transmission input for use by the CPUC in the next cycle of portfolio development. The following provides a description of the assessments the ISO undertakes under the umbrella of the overall policy-driven transmission analysis to integrate the resources identified in the CPUC portfolios to meet the state's greenhouse gas goals.

Policy-driven reliability assessment

The policy-driven reliability assessment is used to identify transmission constraints that need to be modeled in production cost simulations to capture the impact of the constraints on renewable curtailment caused by transmission congestion. The reliability assessment component of the overall policy-driven analysis is addressed in the reliability assessment presented in Chapter 2 and Appendix B.

On-peak deliverability assessment

The on-peak deliverability assessment is designed to ensure portfolio resources selected with full capacity deliverability status (FCDS) are deliverable and can count towards meeting resource adequacy needs. The assessment examines whether sufficient transmission capability exists to transfer resource output from a given sub-area to the aggregate of the ISO control-area load when the generation is needed most. The ISO performs the assessment in accordance with the On-peak Deliverability Assessment Methodology.[51]

Off-peak deliverability assessment

The off-peak deliverability assessment is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. The ISO performs the assessment in accordance with the Off-Peak Deliverability Assessment Methodology.[52]

Production cost model (PCM) simulation

Production cost models for the base and sensitivity portfolios are used to identify renewable curtailment and transmission congestion in the ISO Balancing Authority Area. The PCM for the base portfolio is used in the policy-driven assessment covered in this section as well as the economic assessment discussed in Chapter 4 and Appendix G. The PCM with the sensitivity portfolios is used in only the policy-driven assessment. Details of PCM modeling assumptions and approaches are provided in Chapter 4 and Appendix G.

[51] http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf

[52] http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf

3.4 Resource Portfolios

As mentioned in Section 3.1, a base portfolio and a sensitivity portfolio were transmitted by the CPUC for study in the ISO 2022-2023 transmission planning process. The detailed portfolios are available at the CPUC website.[53]

Table 3.4-1 includes the total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO). The portfolios are comprised of solar, wind (in-state, out-of-state and offshore), battery storage, geothermal, long duration energy storage, biomass/biogass and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.4-1: Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	5,490	11,889	**17,379**	12,068	28,686	**40,754**
Wind – In State	2,533	499	**3,032**	2,697	546	**3,244**
Wind – Out-of-State (Existing TX)	610	-	**610**	610	-	**610**
Wind – Out-of-State (New TX)	1,500	-	**1,500**	4,828	-	**4,828**
Wind - Offshore	1,588	120	**1,708**	4,587	120	**4,707**
Li Battery	13,564	-	**13,564**	28,402	-	**28,402**
Geothermal	1,159	-	**1,159**	1,794	-	**1,794**
Long Duration Energy Storage (LDES)	1,000	-	**1,000**	2,000	-	**2,000**
Biomass/Biogass	134	-	**134**	134	-	**134**
Distributed Solar	125	-	**125**	125	-	**125**
Total	**27,703**	**12,508**	**40,211**	**57,246**	**29,352**	**86,598**

3.4.1 Mapping of portfolio resources to transmission substations

The portfolios that RESOLVE[54] generates are at the zonal level. As a result, the portfolios have to be mapped to the busbar level for use in the ISO transmission planning process. The resource-to-busbar mapping process is documented in the CPUC report entitled *Methodology for Resource-to-Busbar Mapping & Assumptions for the Annual TPP*[55] with further refinements as described in the CPUC staff report entitled *Modeling Assumptions for the 2022-2023 Transmission Planning Process.*[56] The detailed documentation of the busbar mapping inputs is discussed in Appendix F. Figure 3.4-1 illustrates the interconnection planning areas that the resources have been mapped to, based upon the CPUC busbar mapping workbooks below, with the total resources in both the base and sensitivity portfolios.

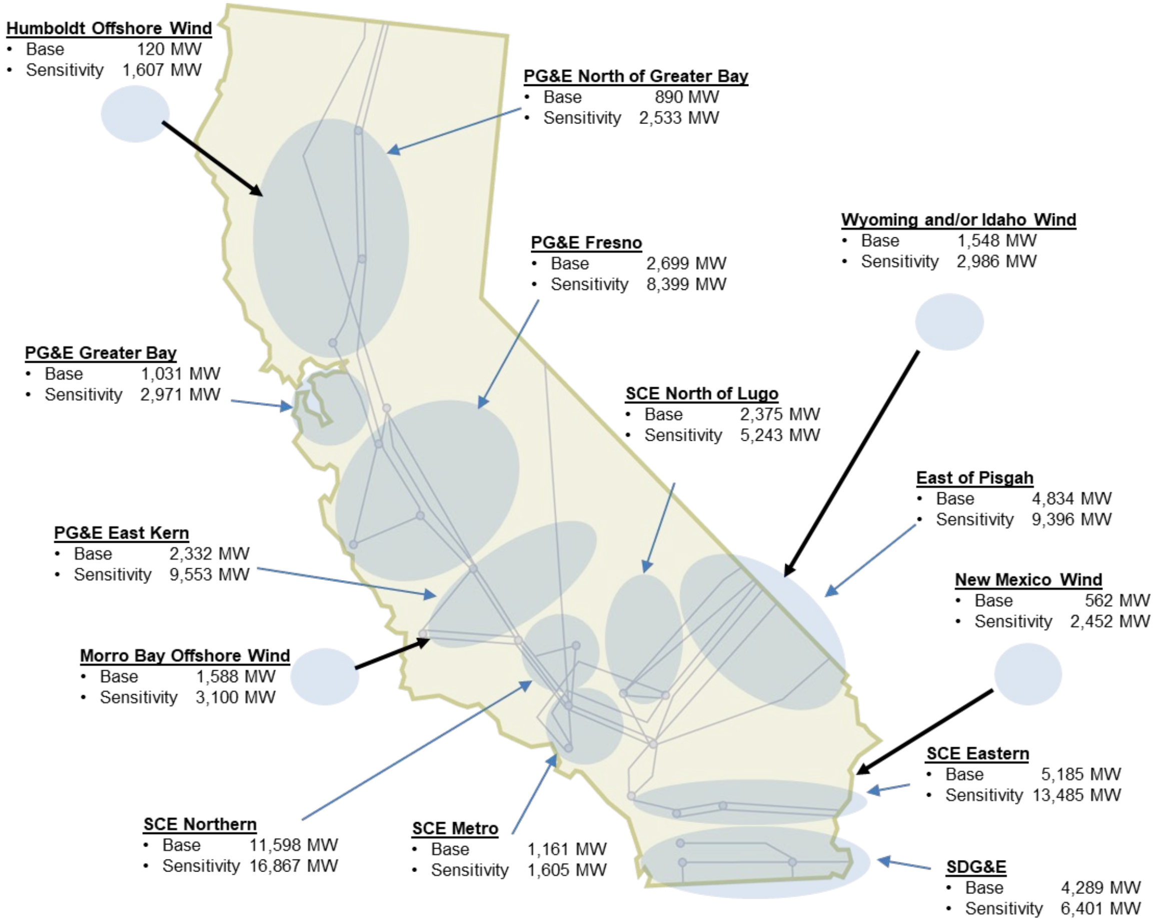
53 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials

54 Is the resource optimization model that the CPUC uses to develop resource portfolios.

55 https://files.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%20the%20TPP_V2021_12_21.pdf

56 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF

Figure 3.4-1: Base and Sensitivity Portfolios Total MW in Each Interconnection Area



3.5 Transmission Interconnection Zone Assessments

The on-peak and off-peak deliverability assessments have been conducted for each of the transmission interconnection zones to determine where constraints are on the transmission system limiting deliverability of the portfolio base and sensitivity resource. The detailed analysis of the policy assessment is included in Appendix F. Transmission mitigation has been recommended to address the constraints so resources in the portfolio can be deliverable.

The ISO then conducts its technical and economic evaluations of the alternatives identified by the ISO or by stakeholders, to select the most effective and efficient recommendation. Details of the technical assessments and comparisons of alternatives are provided in Appendix F.

The following section identifies the recommended policy-driven projects that are recommended for approval. In total, the policy assessment has identified 21 new policy-driven projects required in this transmission planning cycle for a total estimated cost of $5.53 billion.

3.5.1 PG&E Greater Bay and North of Greater Bay Interconnection Area

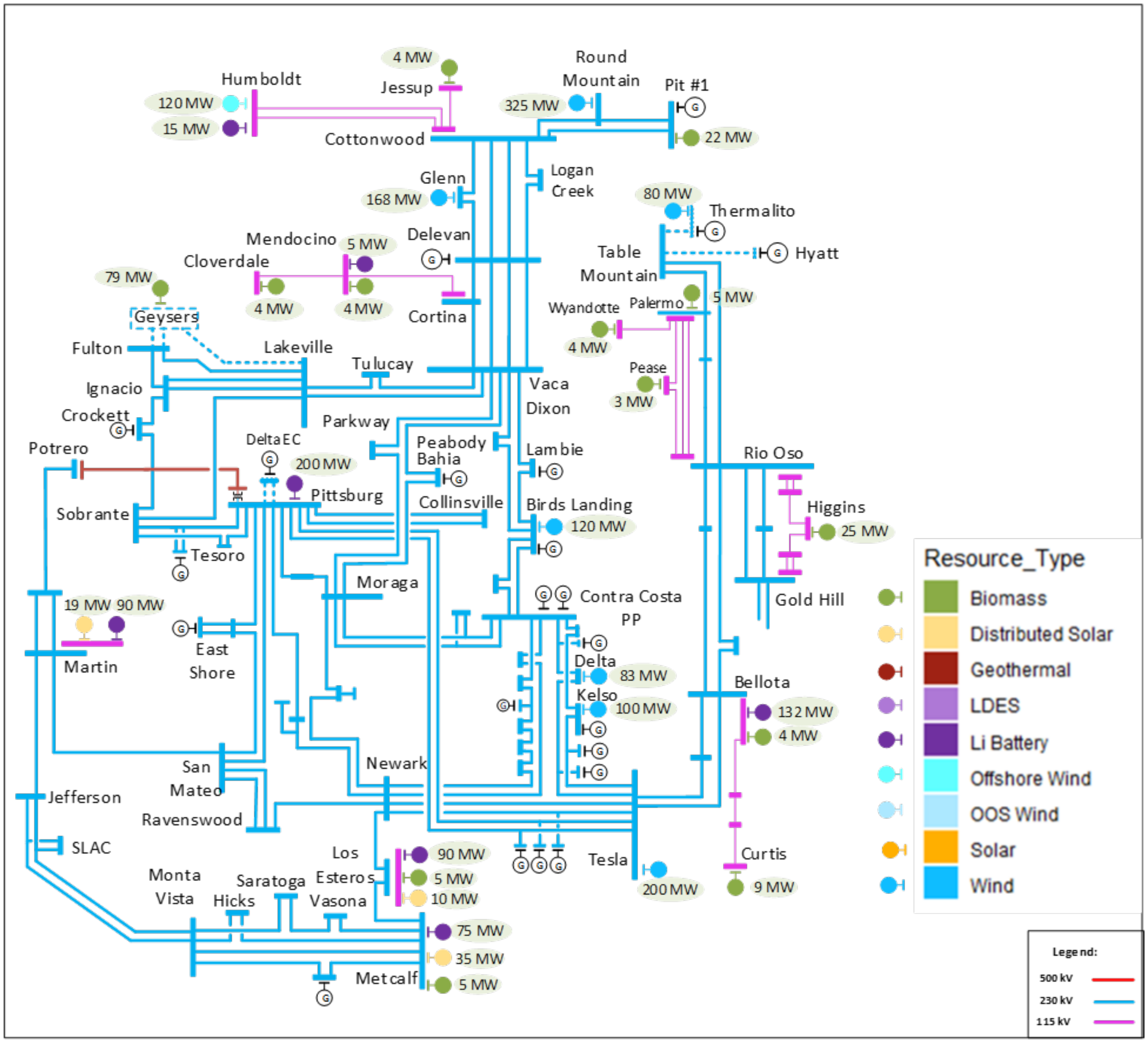
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Bay and North of Greater Bay interconnection area are listed in Table 3.5-1. The portfolios in the interconnection area are comprised of solar, wind (in-state and offshore), battery storage, geothermal, biomass/biogass and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-1: PG&E Greater Bay and North of Greater Bay Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	-	-	-	344	1,512	1,856
Wind – In State	577	499	1,076	626	546	1,172
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	-	120	120	1,487	120	1,607
Li Battery	607		607	2,198	-	2,198
Geothermal	79	-	79	119	-	119
Long Duration Energy Storage (LDES)	-	-		-	-	-
Biomass/Biogass	95	-	95	95	-	95
Distributed Solar	64	-	64	64	-	64
Total	**1,422**	**619**	**2,041**	**4,933**	**2,178**	**7,111**

The resources as identified in the CPUC busbar mapping for the PG&E Greater Bay and North of Greater Bay interconnection area are illustrated on the single-line diagram in Figure 3.5-1.

Figure 3.5-1: Greater Bay and North of Greater Bay Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the Greater Bay and North of Greater Bay interconnection areas along with the recommended mitigation plans are identified in Figure 3.5-2.

Table 3.5-2: Greater Bay and North of Greater Bay Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Collinsville – Pittsburg E 230 kV Lines	Base	40	0	0	1,342	Reduce the overall series compensation on the Table Mountain-Vaca-Collinsville-Tesla 500 kV path.
	Sensitivity	1,527	0	0	2,629	
Cloverdale – Eagle Rock 115 kV Line	Base	79	0	41	38	Portfolio resource to be moved to higher kV level
	Sensitivity	0	0	0	264	
Eagle Rock- Fulton-Silverado 115 kV Line	Base	133	5	114	24	Continue to monitor
	Sensitivity	-	-	-	-	None required
Humboldt Bay Area 60 kV	Base	0	15	0	71	Garberville Area Reinforcement reliability project recommended for approval in this cycle
	Sensitivity	0	15	0	240	
Cortina No. 4 60 kV Line	Base	50	0	42	8	Portfolio resource to be moved to higher kV level
	Sensitivity	-	-	-	-	None required

Based on the constraints identified in Table 3.5-2, there are no policy-driven upgrades identified in the Greater Bay and the North of Greater Bay interconnection planning areas. To mitigate the Collinsville-Pittsburg constraint, it is recommended to reduce the overall series compensation on the Table Mountain-Vaca-Collinsville-Tesla 500 kV path. The ISO continue to will work with PG&E for feasibility and determination of the most effective series cap arrangement for the 500 kV path. For the Humboldt Bay Area 60 kV constraint, the reliability-driven project identified in Chapter 2 as the Garberville Area Reinforcement project will mitigate the identified constraint.

The constraints identified in Table 3.5-3 were only observed in the sensitivity portfolio and not in the base portfolio. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle. For the North Dublin-Vinyard 230 kV constraint, the reliability-driven project identified in Chapter 2 as the Lone Tree – Cayetano – Newark Corridor Series Compensation project will mitigate the identified constraint.

Table 3.5-3: Greater Bay and North of Greater Bay Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Generic Portfolio MW behind the constraint	Generic Battery storage portfolio MW behind the constraint	Deliverable Generic Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Potential Mitigation
East Shore – San Mateo 230 kV line	Sensitivity	828	400	781	446	Reduce the overall series compensation on the Table Mountain-Vaca-Collinsville-Tesla 500 kV.
North Dublin – Vineyard 230 kV line	Sensitivity	0	150	121	28	Contra Costa - Lone Tree Series compensation TPP project
Lincoln - Pleasant Grove 115 kV Line	Sensitivity	0	127	5	122	Possible RAS or Reconductor
Stanislaus-Melones-Manteca 115 kV Line No.1	Sensitivity	0	287	201	86	Reconductor
Drum – Higgins 115 kV	Sensitivity	0	0	0	34	Reconductor

<u>Off-Peak Deliverability Assessment</u>

In the off-peak deliverability assessment of the Greater Bay and North of Greater Bay interconnection there were no constraints identified for the base portfolios. The constraints that were observed in the sensitivity portfolio only are listed in Table 3.5-4. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle.

Table 3.5-4: Greater Bay and North of Greater Bay Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Midway-Gates 500 kV line	Sensitivity	6,964	2,279	1,748	Portfolio energy storage in charging mode
Moss Landing-Los Banos 500 kV line	Sensitivity	13,284	5,466	4,729	Portfolio energy storage in charging mode
Belridge J-Pumpjack Tp	Sensitivity	55	55	26	Portfolio energy storage in charging mode
Borden-Storey #1/#2 230 kV	Sensitivity	4,264	2,168	2,683	Portfolio energy storage in charging mode
Quinto-Los Banos 230 kV line	Sensitivity	13,394	5,462	4,082	Portfolio energy storage in charging mode.
Gates-Arco 230 kV line	Sensitivity	2,751	1,674	272	Portfolio energy storage in charging mode
Los Banos-Panoche #2 230 kV	Sensitivity	1,569	880	1,040	Portfolio energy storage in charging mode

Constraint	Portfolio	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Schindler-Coalinga #2 70 kV Line (Schindler-Paige Section)	Sensitivity	150	75	93	Portfolio energy storage in charging mode
Tesla-Westley 230 kV line	Sensitivity	5,631	2,839	1,503	Portfolio energy storage in charging mode
Wesltey-Q1244 SS 230 kV line	Sensitivity	13,394	5,462	3,714	Portfolio energy storage in charging mode
Wilson-Dairyland 115 kV Line	Sensitivity	100	75	62	Portfolio energy storage in charging mode
Arco-Midway 230 kV line	Sensitivity	586	318	181	Portfolio energy storage in charging mode
Gregg - Mustang 230 kV line	Sensitivity	8,891	3,099	1,485	Reconductor if economic
Gates - Manning 500 kV line	Sensitivity	9,604	3,588	4,888	Reconductor or new line if economic.
Panoche 115 kV Area	Sensitivity	150	85	104	Reconductor or new line if economic.
Panoche 230 kV Area	Sensitivity	3,100	1,352	2,361	Reconductor or new line if economic.
Panoche 70 kV Area	Sensitivity	150	75	104	Reconductor or new line if economic.

3.5.2 PG&E Greater Fresno Interconnection Area

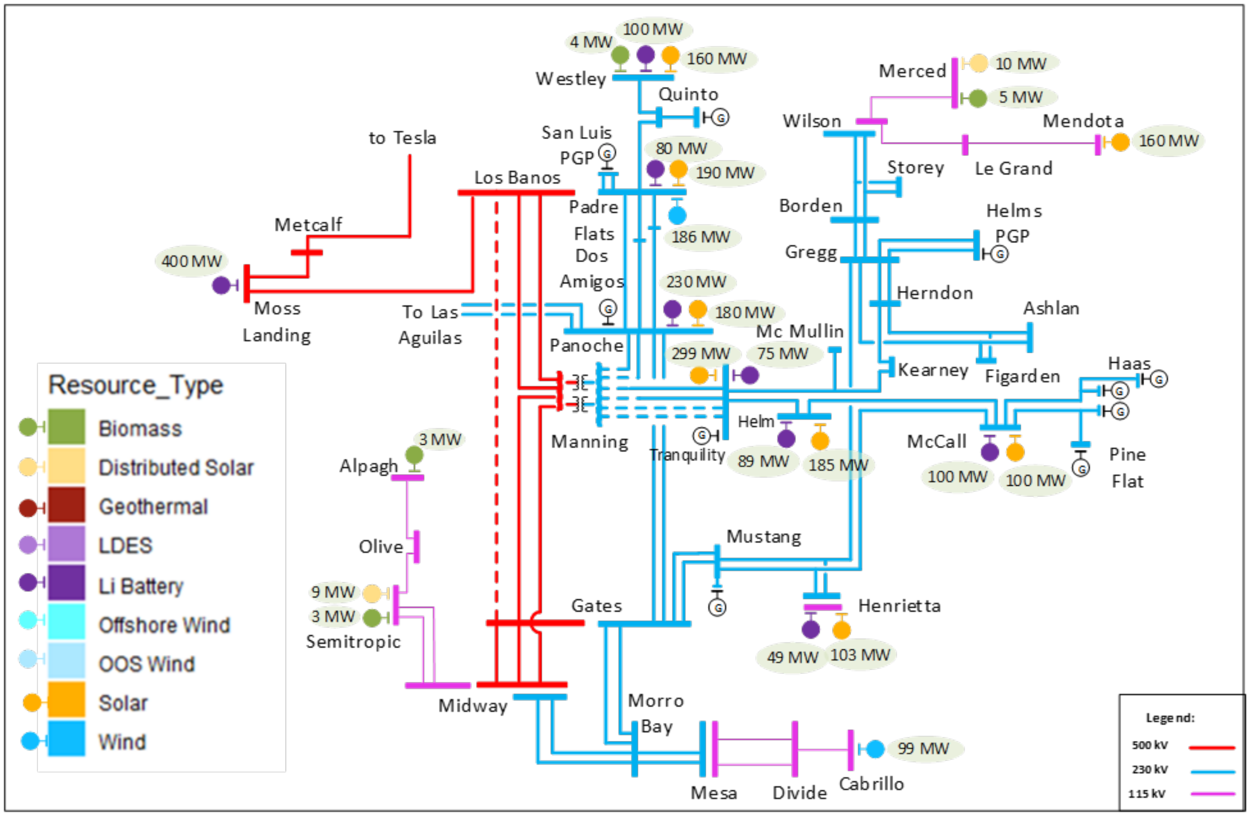
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Fresno interconnection area are listed in Table 3.5-5. The portfolios are comprised of solar, wind (in-state), battery storage, biomass/biogass and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-5: PG&E Greater Fresno Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	447	930	**1,377**	1,527	3,530	**5,057**
Wind – In State	285	-	**285**	285	-	**285**
Wind – Out-of-State (Existing TX)	-	-	**-**	-	-	**-**
Wind – Out-of-State (New TX)	-	-	**-**	-	-	**-**
Li Battery	1,003	-	**1,003**	3,023	-	**3,023**
Geothermal	-	-	**-**	-	-	**-**
Long Duration Energy Storage (LDES)	-	-	**-**	-	-	**-**
Biomass/Biogass	15	-	**15**	15	-	**15**
Distributed Solar	19	-	**19**	19	-	**19**
Total	**1,769**	**930**	**2,699**	**4,869**	**3,530**	**8,399**

The resources as identified in the CPUC busbar mapping for the PG&E Greater Fresno interconnection area are illustrated on the single-line diagram in Figure 3.5-2.

Figure 3.5-2: PG&E Greater Fresno Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the Greater Fresno interconnection area along with the recommended mitigation plans are identified in Table 3.5-6.

Table 3.5-6: PG&E Greater Fresno Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Borden - Storey #1 and #2 230 kV lines	Base	18	139	0	581	Borden-Storey 230 kV lines reconductoring project
	Sensitivity	79	2,168	0	2,689	
Henrietta 230/115 kV Bank 3	Base	0	0	0	191	Henrietta 230/115 kV Bank 3 replacement project
	Sensitivity	0	0	0	300	

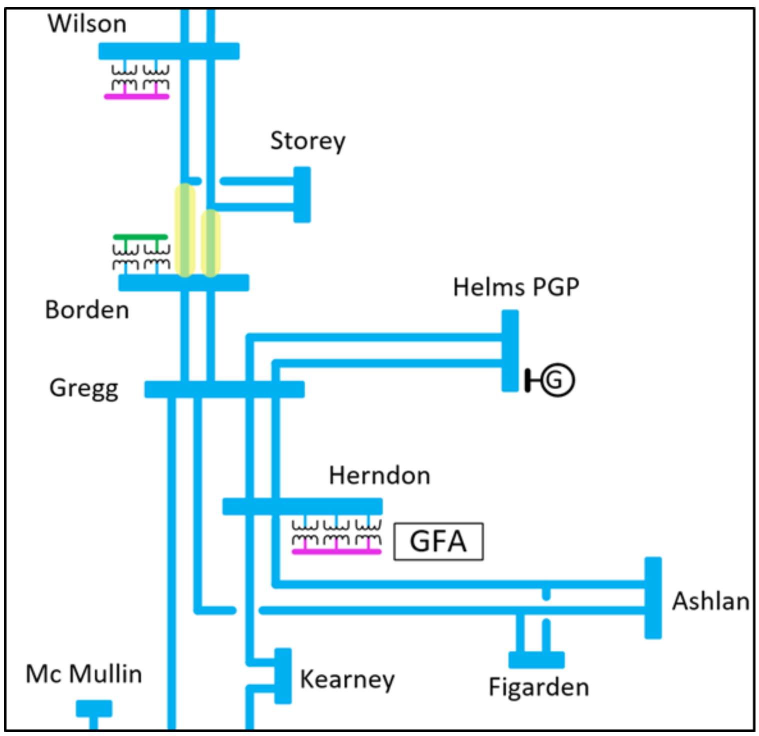
Two policy-driven projects are recommended to mitigate the constraints in the Greater Fresno interconnection area.

Borden-Storey 230 kV 1 and 2 Line Reconductoring

To address Borden-Storey 1 and 2 230 kV line constraint identified in the base and sensitivity portfolios the ISO recommends the approval of reconductoring the Borden – Storey 230 kV 1 and 2 Line Reconductoring project as illustrated in Figure 3.5-3. The estimated project cost is between $25 million and $50 million and is expected to be in-service before 2032.

RAS was considered as an alternative but was not selected as it does not meet the RAS standards and guidelines in ISO Planning Standards. Series compensation was also considered as an alternative but was not selected due to the size of compensation that would be required to mitigate the constraint.

Figure 3.5-3: Borden-Storey 230 kV 1 and 2 Lines Reconductoring Project

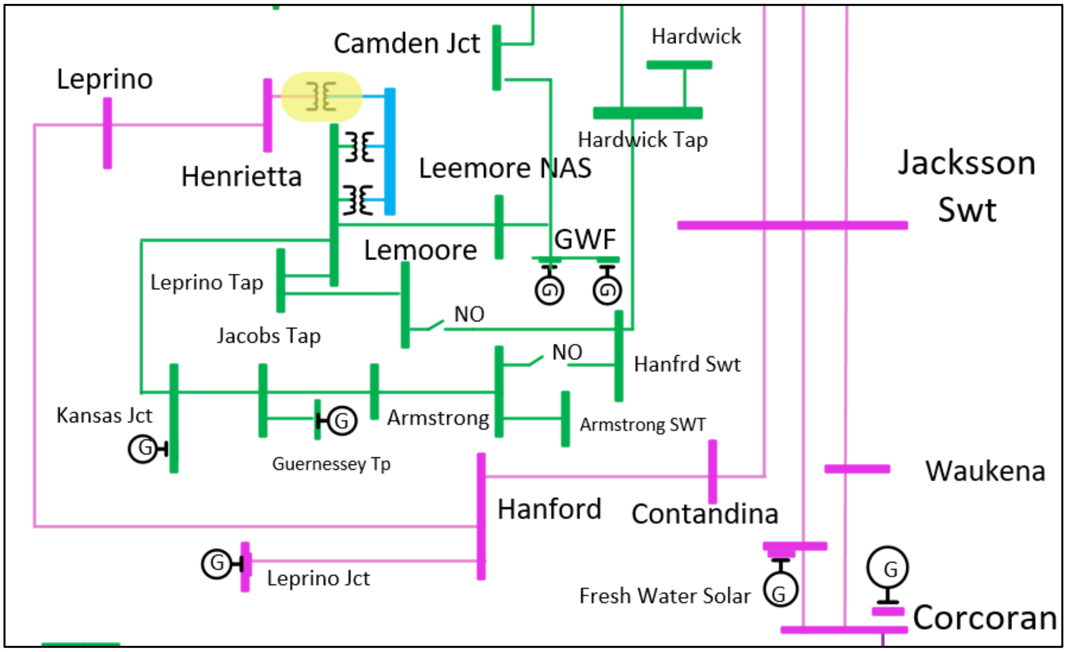


Henrietta 230/115 kV Bank 3 Replacement

To address Henrietta 230/115 kV Bank 3 constraint identified in the base and sensitivity portfolios the ISO recommends the approval of Henrietta 230/115 kV Bank 3 Replacement project as illustrated in Figure 3.5-4. The estimated project cost is between $12 million and $20 million and is expected to be in-service before 2032.

RAS was considered as an alternative but was not selected as it does not meet the RAS standards and guidelines in the ISO Planning Standards.

Figure 3.5-4: Henrietta 230/115 kV Bank 3 Replacement Project



The constraints identified in Table 3.5-7 were only observed in the sensitivity portfolio and not in the base portfolio. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle.

Table 3.5-7: PG&E Greater Fresno Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Generic Portfolio MW behind the constraint	Generic Battery storage portfolio MW behind the constraint	Deliverable Generic Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Potential Mitigation
Las Aguilas – Moss Landing 230 kV line	Sensitivity	3150	880	3155	875	Re-evaluate previously approved series reactor on the Moss Landing – Las Aguilas 230 kV line
McCall 115/230 kV Bank 1	Sensitivity	167	509	484	193	RAS or Bank replacement
Gates-Gregg 230 kV Line	Sensitivity	3948	810	3792	1774	Reconductor Line
Melones-Cottle 230 kV line	Sensitivity	18	335	263	90	Reconductor Line
Barton-Airways-Sanger 115 kV line	Sensitivity	0	509	0	940	Reconductor Line

Constraint	Portfolio	Generic Portfolio MW behind the constraint	Generic Battery storage portfolio MW behind the constraint	Deliverable Generic Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Potential Mitigation
Herndon – Woodward 115 kV line	Sensitivity	3	260	1	262	Reconductor Line
GWF-Kingsburg 115 kV Line	Sensitivity	25	54	0	626	Reconductor Line
Corcoran-Smyrna (Alpaugh-Smyrna) 115 kV line	Sensitivity	23	175	153	45	Reconductor Line

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the Greater Fresno interconnection areas along with the recommended mitigation plans are identified in Table 3.5-8.

Table 3.5-8: PG&E Greater Fresno Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Kettlemen – Gates 70 kV line	Base	-	10	1	None required
	Sensitivity	-	-	-	
Warnerville – Willison 230 kV Line	Base	398	228	1,420	
	Sensitivity	1,698	1,098	831	
Los Banos 500 kV	Base	3,404	932	2,786	
	Sensitivty	11,858	4,877	7,517	

The constraints identified in Table 3.5-9 were only observed in the sensitivity portfolio and not in the base portfolio. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle.

Table 3.5-9: PG&E Greater Fresno Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Midway-Gates 500 kV line	Sensitivity	6,964	2,279	1,748	Portfolio energy storage in charging mode
Moss Landing-Los Banos 500 kV line	Sensitivity	13,284	5,466	4,729	Portfolio energy storage in charging mode
Belridge J-Pumpjack Tp	Sensitivity	55	55	26	Portfolio energy storage in charging mode
Borden-Storey #1/#2 230 kV	Sensitivity	4,264	2,168	2,683	Portfolio energy storage in charging mode
Quinto-Los Banos 230 kV line	Sensitivity	13,394	5,462	4,082	Portfolio energy storage in charging mode.
Gates-Arco 230 kV line	Sensitivity	2,751	1,674	272	Portfolio energy storage in charging mode
Los Banos-Panoche #2 230 kV	Sensitivity	1,569	880	1,040	Portfolio energy storage in charging mode
Schindler-Coalinga #2 70 kV Line (Schindler-Paige Section)	Sensitivity	150	75	93	Portfolio energy storage in charging mode
Tesla-Westley 230 kV line	Sensitivity	5,631	2,839	1,503	Portfolio energy storage in charging mode
Wesltey-Q1244 SS 230 kV line	Sensitivity	13,394	5,462	3,714	Portfolio energy storage in charging mode
Wilson-Dairyland 115 kV Line	Sensitivity	100	75	62	Portfolio energy storage in charging mode
Arco-Midway 230 kV line	Sensitivity	586	318	181	Portfolio energy storage in charging mode
Gregg - Mustang 230 kV line	Sensitivity	8,891	3,099	1,485	Reconductor if economic
Gates - Manning 500 kV line	Sensitivity	9,604	3,588	4,888	Reconductor or new line if economic.
Panoche 115 kV Area	Sensitivity	150	85	104	Reconductor or new line if economic.
Panoche 230 kV Area	Sensitivity	3,100	1,352	2,361	Reconductor or new line if economic.
Panoche 70 kV Area	Sensitivity	150	75	104	Reconductor or new line if economic.

3.5.3 PG&E East Kern Interconnection Area

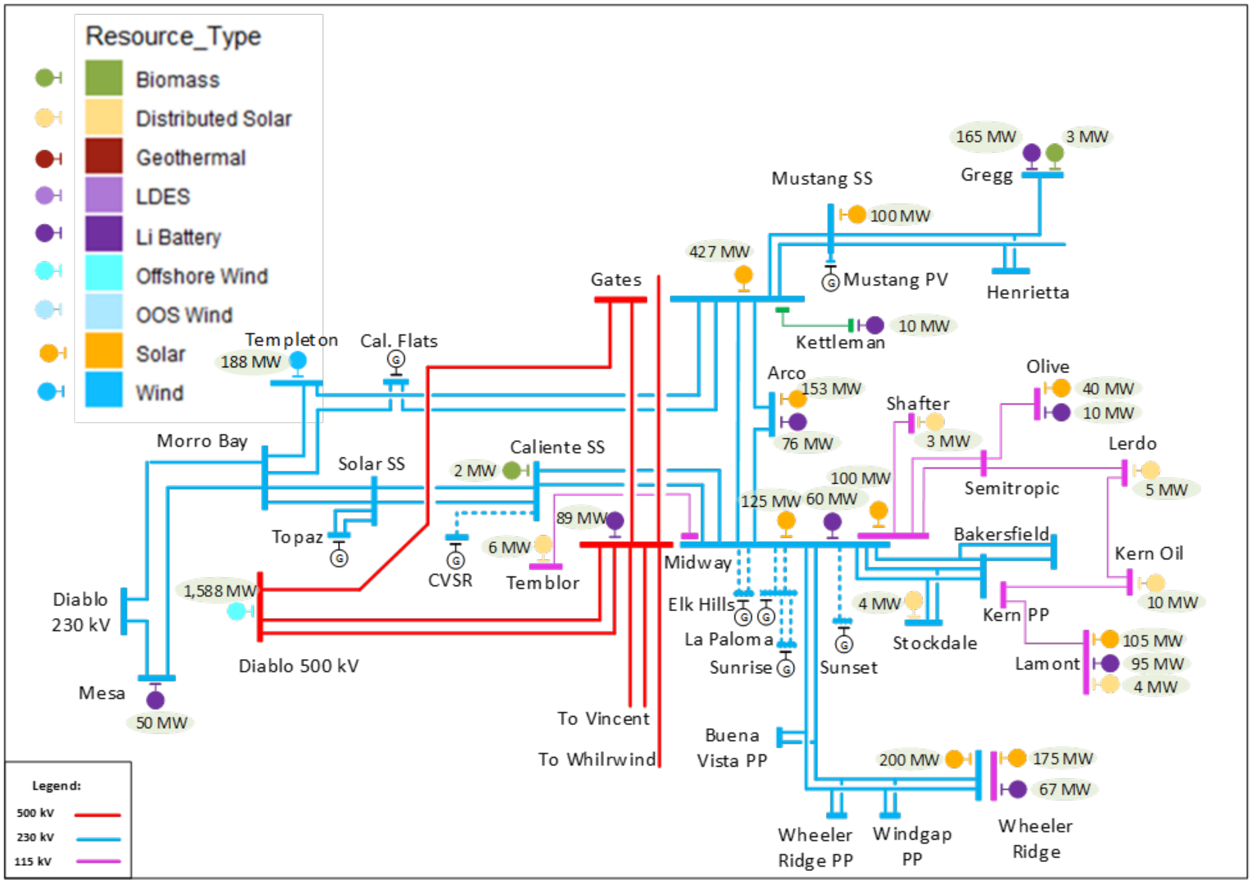
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E East Kern interconnection area are listed in Table 3.5-10. The portfolios in the interconnect area are comprised of solar, wind (in-state and offshore), battery storage, biomass/biogass and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-10: PG&E East Kern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	575	850	1,425	2,008	3,909	5,917
Wind – In State	248	-	248	188	-	248
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-			-	-
Wind – Offshore	1,588	-	1,588	3,100	-	3,100
Li Battery	622	-	622	3,052	-	3,052
Geothermal	-	-	-	-	-	-
Long Duration Energy Storage (LDES)	-	-	-	300	-	300
Biomass/Biogass	5	-	5	5	-	5
Distributed Solar	32	-	32	32	-	32
Total	**3,070**	**850**	**3,920**	**8,685**	**3,909**	**12,653**

The resources as identified in the CPUC busbar mapping for the PG&E East Kern interconnection area are illustrated on the single-line diagram in Figure 3.5-5.

Figure 3.5-5: PG&E East Kern Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the East Kern interconnection area along with the recommended mitigation plans are identified in Table 3.5-11.

Table 3.5-11: PG&E East Kern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Wheeler 115/70 kV Bank 2	Base	0	67	53	14	Wheeler Ridge Junction previously approved reliability project currently on hold recommended to proceed in Chapter 2
	Sensitivity	70	117	103	84	
Arco-Cholame 70 kV Line	Base	60	0	31	14	Portfolio resource to be moved to higher kV level
	Sensitivity	-	-	-	-	

Based on the constraints identified in Table 3.5-11, there are no policy-driven upgrades identified in the East Kern interconnection planning areas. For the Wheeler 115/70 kV Bank 2 constraint, the previously approved reliability-driven project identified in Chapter 2 as the Wheeler Ridge Junction project that is currently on hold and recommended to proceed with a scope change will mitigate the identified constraint.

The constraints identified in Table 3.5-12 were only observed in the sensitivity portfolio and not in the base portfolio. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle.

Table 3.5-12: PG&E East Kern Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Generic Portfolio MW behind the constraint	Generic Battery storage portfolio MW behind the constraint	Deliverable Generic Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Potential Mitigation
Semitropic-Famoso 115 kV line	Sensitivity	35	250	81	204	Reconductor Line
Temblor-San Luis Obispo 115 kV line	Sensitivity	6	55	0	84	Reconductor LIne
Semitropic-Wasco 70 kV line	Sensitivity	12	220	154	78	Reconductor Line
Temblor-PSE MCKJ 115 kV line	Sensitivity	106	55	33	22	Reconductor Line

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the East Kern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-13.

Table 3.5-13: PG&E East Kern Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Kern-TEvis-Stockdale 1 and 2 115 kV	Base	109	95	57	Charging mode of Storage
	Sensitivity	304	135	179	Continue to assess in next planning cycle

3.5.4 East of Pisgah Interconnection Area

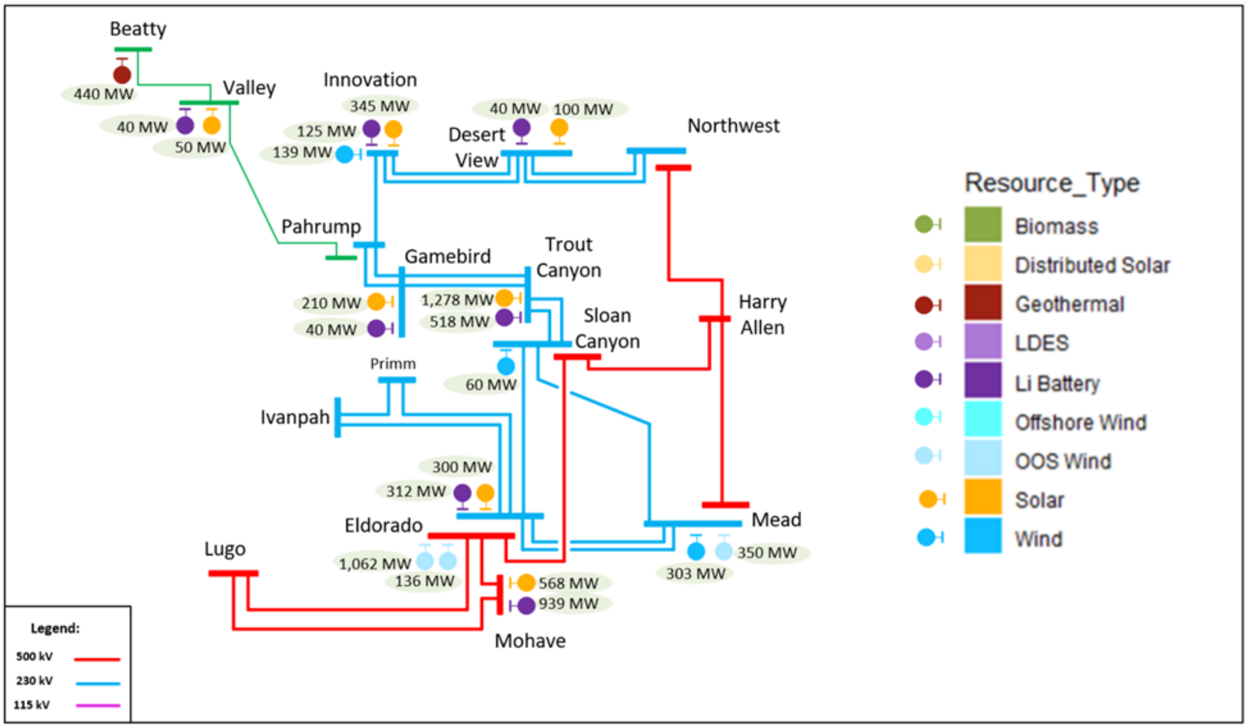
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the East of Pisgah interconnection area are listed in Table 3.5-14. The portfolios in the interconnection area are comprised of solar, wind (in-state and out-of-state), battery storage and geothermal resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-14: East of Pisgah Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	770	1,946	**2,716**	1,320	4,196	**5,516**
Wind – In State	442	-	**442**	442	0	**442**
Wind – Out-of-State (Existing TX)	486	-	**486**	486	0	**486**
Wind – Out-of-State (New TX)	1,062	-	**1,062**	2,500	0	**2,500**
Wind – Offshore	-	-	**-**	0	0	**0**
Li Battery	1,236	-	**1,236**	2,711	0	**2,711**
Geothermal	440	-	**440**	727	0	**727**
Long Duration Energy Storage (LDES)	-	-	**-**	0	0	**0**
Biomass/Biogass	-	-	**-**	0	0	**0**
Distributed Solar	-	-	**-**	0	0	**0**
Total	**4,436**	**1,946**	**6,382**	**8,186**	**4,196**	**12,382**

The resources as identified in the CPUC busbar mapping for the East of Pisgah interconnection area are illustrated on the single-line diagram in Figure 3.5-6.

Figure 3.5-6: East of Pisgah Interconnection Area – Mapped[57] Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the East of Pisgah interconnection areas along with the recommended mitigation plans are identified in Table 3.5-15.

Table 3.5-15: East of Pisgah Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
VEA 138 kV System	Base	480	40	120	360	Beatty 230 kV Project
	Sensitivity	1,330	590	430	900	
GLW 230 kV System	Base	2,253	635	2,034	219	Innovation RAS
	Sensitivity	4,102	2,022	2,456	1,646	Trout Canyon – Sloan Canyon 500 kV upgrade
Lugo-Victorville 500 kV	Base	6,895	2,246	6,500	395	Expand the Lugo – Victorville RAS
	Sensitivity	16,374	6,789	11,380	4,994	Trout Canyon – Lugo 500 kV line; or Eldorado – Lugo 500 kV 2 Line

57 Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the East of Pisgah Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

To mitigate the VEA 138 kV and the GLW 230 kV, the ISO is recommending one new transmission project and to modify the scope of one previously approved project as follows.

GLW/VEA Area Upgrades – Revised Scope

To mitigate the GLW 230 kV System constraint, the ISO is recommending to re-scope the previously approve GLW/VEA Area Upgrades project that was approved in the 2021-2022 Transmission Plan. The scope of the previously approved project is as follows.

- Rebuild Northwest – Desert View, Pahrump – Gamebird, Gamebird – Trout Canyon and Trout Canyon – Sloan Canyon 230 kV to double circuit lines;
- Install a second Innovation – Desert View 230 kV line;
- Rebuild Innovation – Pahrump 230 kV line;
- Add a 500/230 kV transformer at Sloan Canyon and loop in the Harry Allen – Eldorado 500 kV line;
- Install a 138 kV phase shifter at Innovation on the planned tie-line to NVE; and
- Upgrade VEA's 230/138 kV Amargosa transformer.

The recommended revised scope of the GLW/VEA Area Upgrades project scope is as follows:

- Install a new Trout Canyon 500 kV bus and three 500/230 kV transformers at Trout Canyon;
- Rebuild Trout Canyon – Sloan Canyon 230 kV DCTL lines to 500 kV DCTL lines;
- Rebuild Northwest – Desert View, Pahrump – Gamebird and Gamebird – Trout Canyon 230 kV to double circuit lines;
- Rebuild Innovation – Desert View 230 kV No.1 line with a normal rating of 1,154 MVA and an emergency rating of 1,578 MVA;
- Install a second Innovation – Desert View 230 kV line;
- Rebuild Innovation – Pahrump 230 kV line;
- Add a 500/230 kV transformer at Sloan Canyon and loop in the Harry Allen – Eldorado 500 kV line;
- Install a 138 kV phase shifter at Innovation on the planned tie-line to NVE; and
- Upgrade VEA's 230/138 kV Amargosa transformer.

The estimated cost of the GLW/VEA Area Upgrades project as approved in the 2021-2022 Transmission Plan was $278 million. The estimated cost of the increased scope is $228 million for a total cost of the recommended re-scoped project of $506 million. The in-service date for the re-scoped GLW/VEA Area Upgrades project is 2027.

<u>Beatty 230 kV Project</u>

To mitigate the VEA 138 kV constraint the ISO recommends approval of the Beatty 230 kV project. The recommended Beatty 230 kV Project scope includes:

- Build a new Johnnie Corner 230 kV station and loop into the Pahrump – Innovation 230 kV line;
- Expand existing Beatty, Lathrop, Valley Switch and Vista 138 kV substations to 230 kV substations;
- Build 32 miles Beatty – Lathrop 230 kV line next to the existing 138 kV line in an adjacent ROW;
- Build 30 miles Johnnie Corner – Valley Switch – Lathrop 230 kV DCTL lines next to the existing 138 kV line in an adjacent ROW; and
- Install a second Johnnie Corner – Innovation and Johnnie Corner – Vista – Pahrump 230 kV line on the Innovation – Pahrump double circuit tower approved in 2021/22 TPP.

The 230 kV line is to be routed parallel to the existing 138 kV lines from Pahrump to Beatty. The 138 kV system is considered to be aging infrastructure nearing the end of life. The 230 kV parallel to the 138 kV lines and stations will allow for when the 138 kV facilities reach the end of life so they can be retired and the load can be served from the parallel 230 kV system. This will defer the costs of converting the stations to 230 kV until they are required. The cost estimate of the Beatty 230 kV Project is $155 million in 2022 dollars with an in-service date of 2027.

Figure 3.5-7: GLW/VEA Transmission System with 2021-2022 Transmission Plan Approved Project

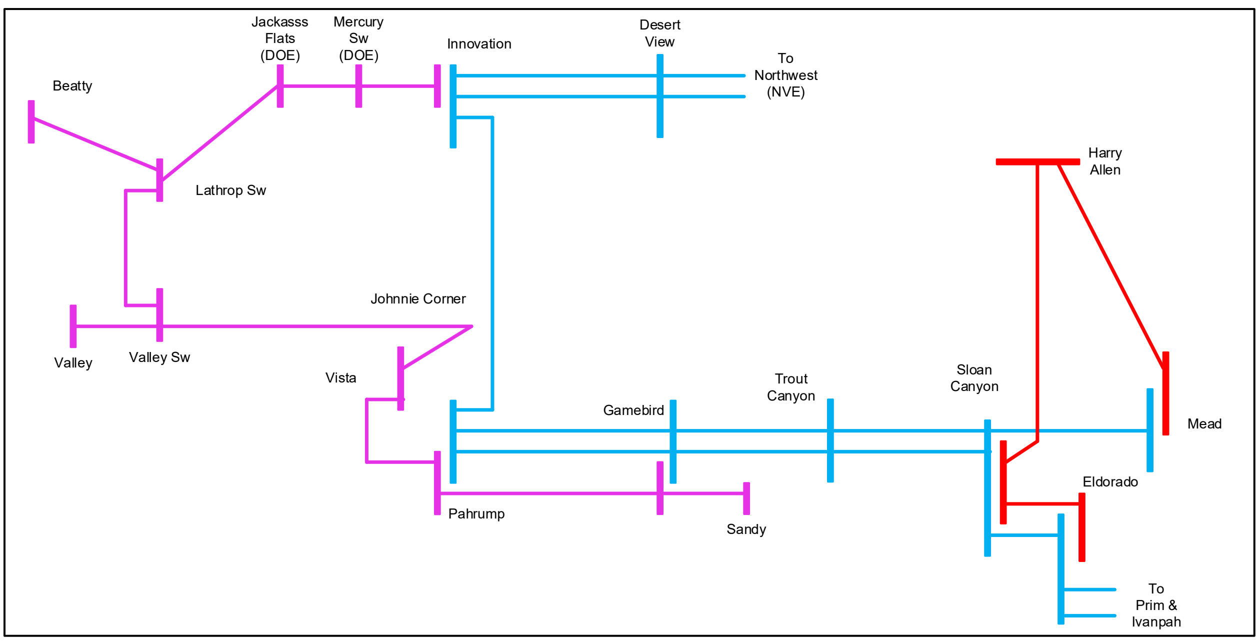
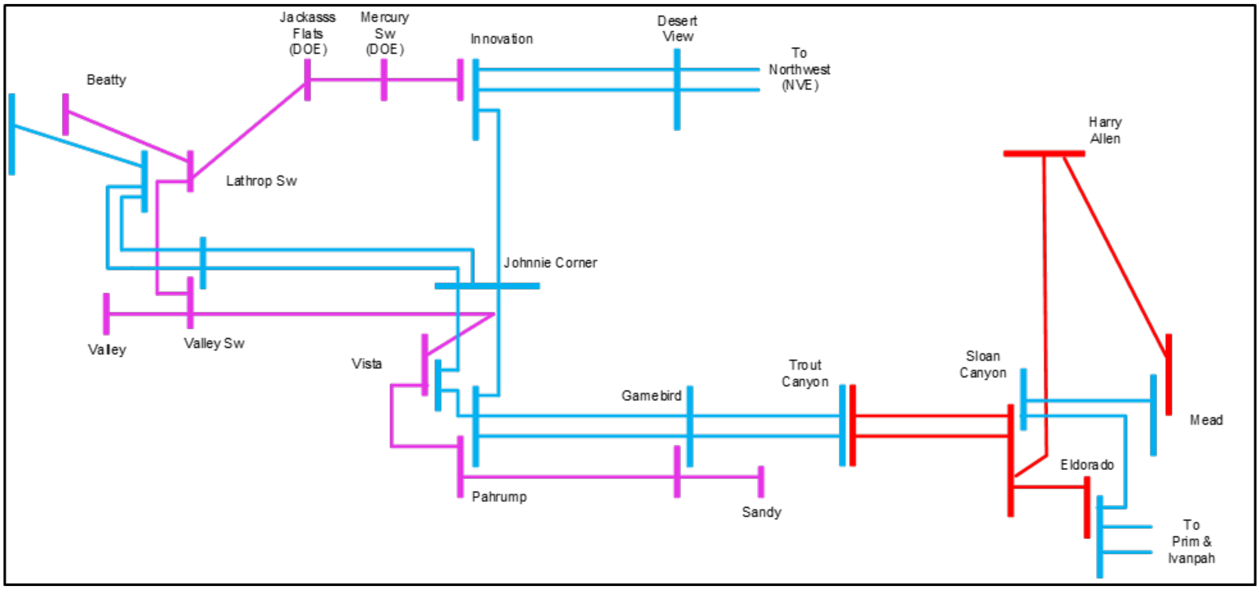
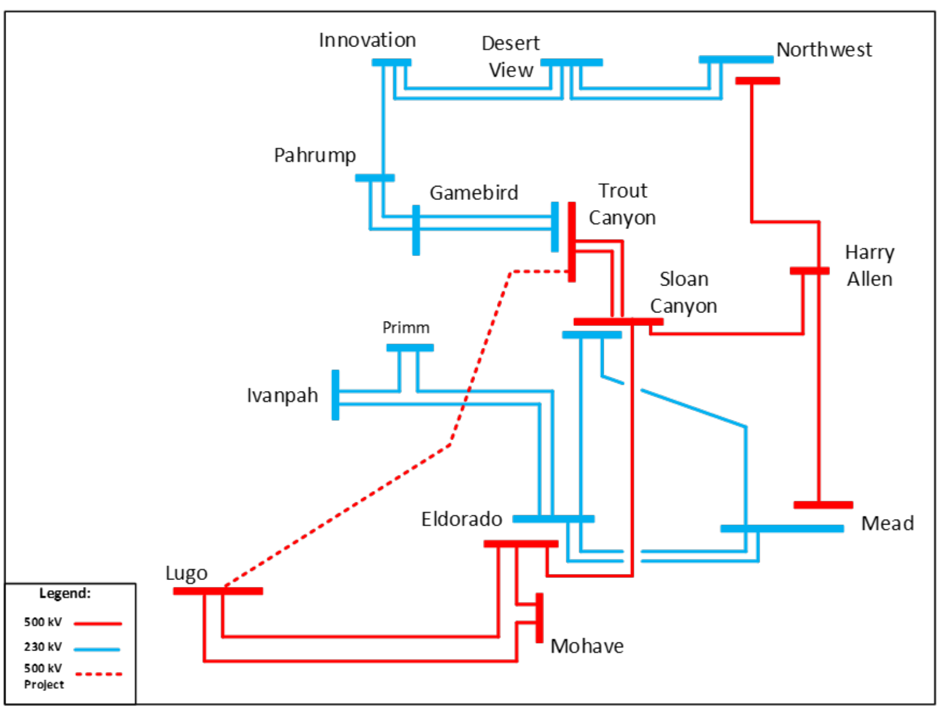


Figure 3.5-8: GLW/VEA Transmission System with Recommended Re-scoping of the GLW/VEA Area Upgrades Project and the Beatty 230 kV Projected



The Lugo – Victorville 500 kV area constraint was identified requiring mitigation in the base portfolio as well as in the sensitivity portfolio. The ISO was intending on recommending approval of the Trout Canyon – Lugo 500 kV Line based upon the alternative analysis to mitigate the constraint.

Figure F.3.5-9: Trout Canyon – Lugo 500 kV Line One-line Diagram



The ISO considered the alternatives of either a Trout Canyon – Lugo 500 kV line and Eldorado – Lugo 500 kV No. 2 line that would mitigate the identified Lugo – Victorville 500 kV area constraints in the sensitivity portfolio analysis. The cost estimate of the Trout Canyon – Lugo 500 kV line project is approximately $1.5 to 2 billion while the cost estimate of the Eldorado – Lugo 500 kV No.2 line project is approximately $2.1 billion. With Eldorado – Lugo 500 kV No. 2 line option, there is a need to build a second Sloan Canyon – Eldorado 500 kV line which has a cost estimate of $14 million, and includes an increase in line crossings in a very congested area. Besides mitigating the Lugo – Victorville 500 kV area constraints, the Trout Canyon – Lugo 500 kV line would improve the deliverability of GLW and VEA area resources and mitigate GLW 230 kV area constraints as indicated in section F.10.2.1. It would also provide opportunity for future transmission expansion in the area and to build transmission access to the geothermal resources in Nevada.

The ISO received a letter from Lotus Infrastructure Partners on April 25, 2023[58] identifying an alternative that the ISO will need to take additional time to assess. The assessment will need to determine how much capacity of the estimated 2,200 MW capacity increase identified would be available to the CAISO and the technical performance of the alternative to meet the needs to address the identified constraint. The ISO will undertake the assessment and will bring forward a recommended mitigation plan for the Lugo – Victorville 500 kV area constraint as either an extension of the 2022-2023 transmission planning process or in the next planning cycle.

<u>Off-Peak Deliverability Assessment</u>

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the East of Pisgah interconnection area along with the recommended mitigation plans are identified in Table 3.5-16.

Table 3.5-16: East of Pisgah Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Eldorado-McCullough 500 kV	Base	6,896	2,467	0	None required
	Sensitivity	8,757	2,605	1,807	Trout Canyon – Lugo 500 kV line; or Eldorado – Lugo 500 kV 2 Line

3.5.5 SCE Northern Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Northern interconnection area are listed in Table 3.5-1. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery storage, long duration energy storage,

[58] http://www.caiso.com/InitiativeDocuments/Letter-Alternative-to-Trout-Canyon-Lugo-500-kV-line-Apr242023.pdf

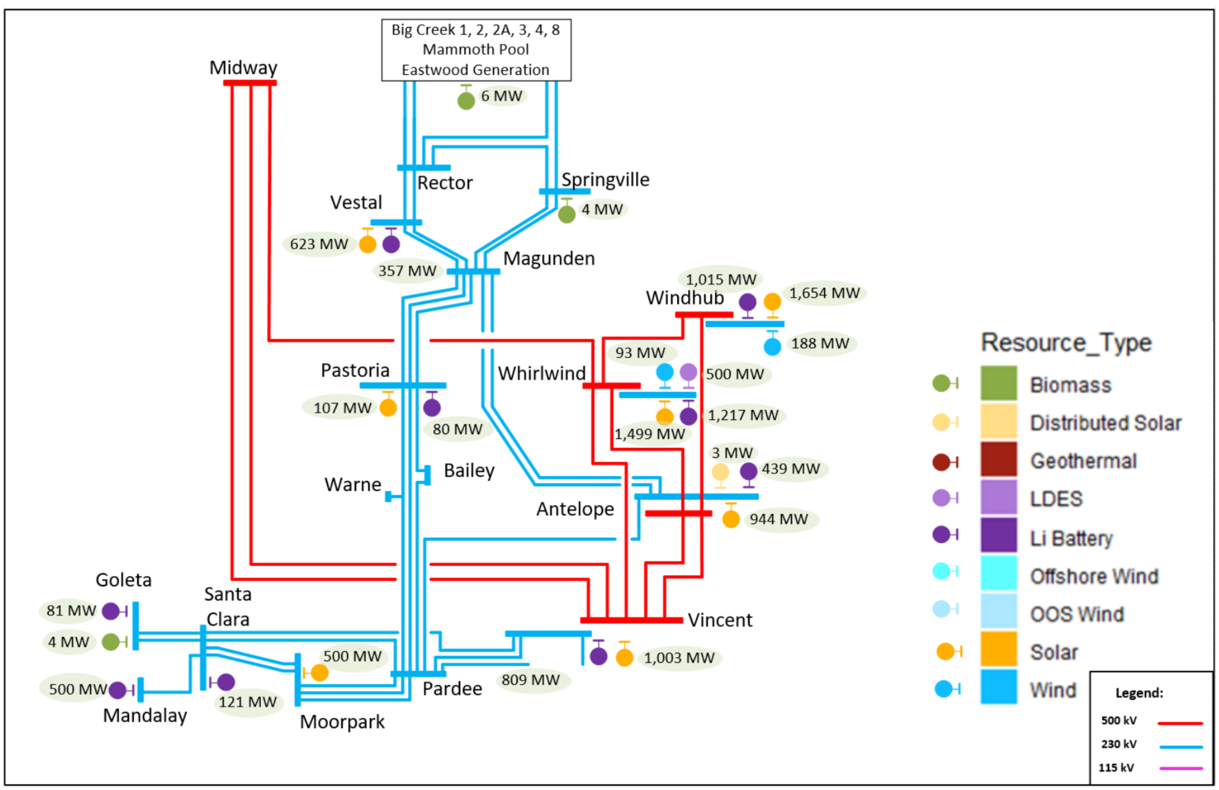
biomass/biogass and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-17: SCE Northern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	1,751	4,505	**6,256**	3,107	7,079	**10,186**
Wind – In State	275	-	**275**	281	-	**281**
Wind – Out-of-State (Existing TX)	-	-	**-**	-	-	**-**
Wind – Out-of-State (New TX)	-	-	**-**	-	-	**-**
Li Battery	4,550	-	**4,550**	6,033	-	**6,033**
Geothermal	-	-	**-**	-	-	**-**
Long Duration Energy Storage (LDES)	500	-	**500**	500	-	**500**
Biomass/Biogass	14	-	**14**	14	-	**14**
Distributed Solar	3	-	**3**	3	-	**3**
Total	**7,093**	**4,505**	**11,598**	**9,987**	**7,079**	**16,867**

The resources as identified in the CPUC busbar mapping for the SCE Northern interconnection area are illustrated on the single-line diagram in Figure 3.5-10.

Figure 3.5-10: SCE Northern Interconnection Area – Mapped[59] Base Portfolio



[59] Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Northern Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE Northern interconnection area along with the recommended mitigation plans are identified in Table 3.5-18.

Table 3.5-18: SCE Northern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Windhub 500/230 kV	Base	0	0	-	108	Planned Windhub CRAS
	Sensitivity	35	0	0	149	

Off-Peak Deliverability Assessment

The Off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE Northern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-19.

Table 3.5-19: SCE Northern Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Mitigation
Windhub 500/230 kV	Base	361	361	306	Planned Windhub CRAS
	Sensitivity	1680	500	814	
Antelope-Vincent 500 kV Lines	Base	N/A	N/A	N/A	Not required
	Sensitivity	7,696	2,098	465	Charging mode of storge
Midway-Whirlwind 500 kV	Base	N/A	N/A	N/A	Not required
	Sensitivity	42,675	14,346	2,188	Charging mode of storage

3.5.6 SCE North of Lugo Interconnection Area

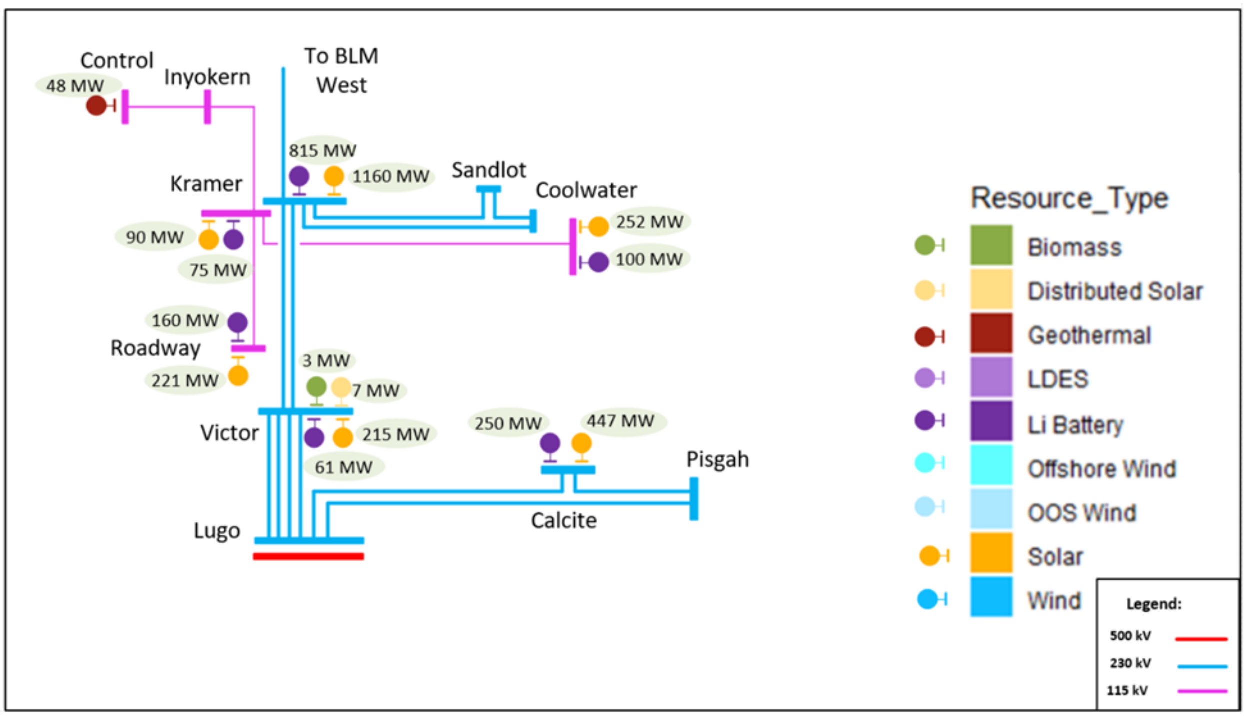
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE North of Lugo interconnection area are listed in Table 3.5-20. The portfolios in the interconnection area are comprised of solar, battery storage, geothermal, biomass/biogass and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-20: SCE North of Lugo Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	385	1,071	**1,456**	770	2,411	**3,181**
Wind – In State	-	-	**-**	100	-	**100**
Wind – Out-of-State (Existing TX)	-	-	**-**	-	-	**-**
Wind – Out-of-State (New TX)	-	-	**-**	-	-	**-**
Wind – Offshore	-	-	**-**	-	-	**-**
Li Battery	869	-	**869**	1,904	-	**1,904**
Geothermal	40	-	**40**	48	-	**48**
Long Duration Energy Storage (LDES)	-	-	**-**	-	-	**-**
Biomass/Biogass	3	-	**3**	3	-	**3**
Distributed Solar	7	-	**7**	7	-	**7**
Total	**1,304**	**1,071**	**2,375**	**2,962**	**2,411**	**5,243**

The resources as identified in the CPUC busbar mapping for the SCE North of Lugo interconnection area are illustrated on the single-line diagram in Figure 3.5-10.

Figure 3.5-11: SCE North of Lugo Interconnection Area – Mapped[60] Base Portfolio



[60] Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE North of Lugo Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE North of Lugo interconnection area along with the recommended mitigation plans are identified in Table 3.5-21.

Table 3.5-21: SCE North of Lugo Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Lugo 500/230 kV Transformer	Base	466	400	0	944	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	1,860	1,132	821	1,092	
Lugo–Victor 230 kV 1, 2, 3 & 4	Base	164	150	0	354	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	1,191	692	843	401	
Kramer-Victor 1 & 2 – 230 kV (Voltage stability and overload)	Base	150	150	0	1,194	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	954	533	26	1,251	
Control-Silver Peak 55 kV	Base	0	0	-	38[61]	Reduce MIC Expansion Request to 15 MW
	Sensitivity	0	0	-	38	
Lugo-Calcite-Pisgah 230 kV Corridor	Base	302	250	237	65	Planned Calcite area RAS
	Sensitivity	669	440	374	295	Further evaluation in 2023-2024 planning cycle

Lugo–Victor–Kramer 230 kV Upgrade

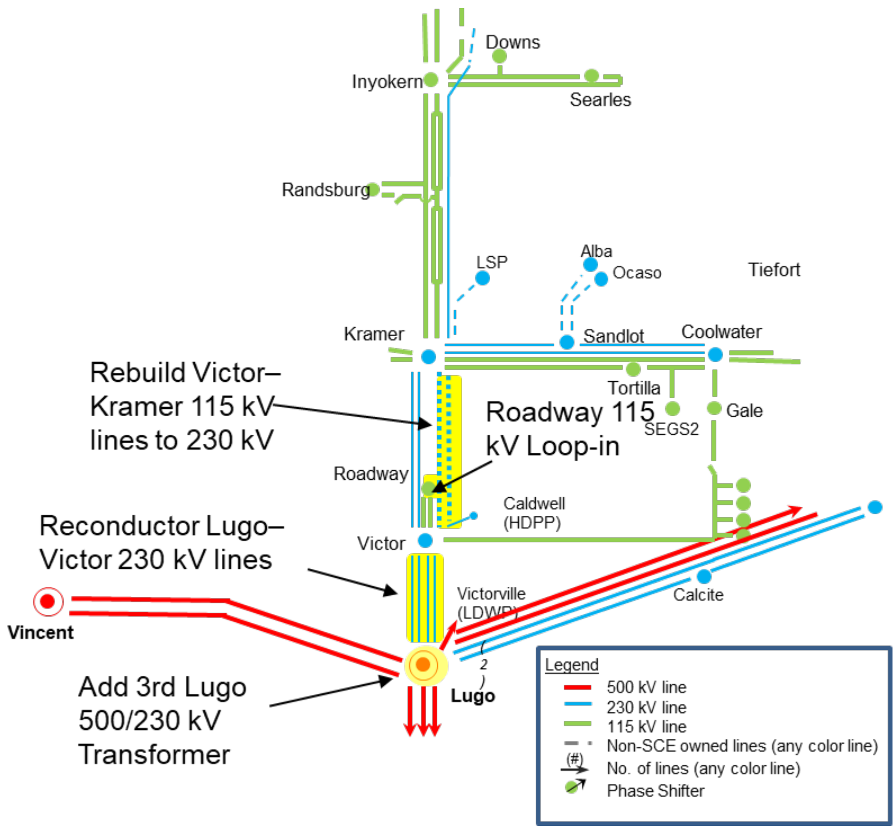
To address the Lugo 500/230 kV Transformer, Lugo-Victor 1, 2, 3 and 4 230 kV and Kramer-Victor 1 and 2 230 kV constraints and voltage instability identified in the base and sensitivity portfolios, the ISO recommends the approval of the Lugo–Victor–Kramer 230 kV Upgrade project as illustrated in Figure 3.5-12. The scope of the project is as follow:

- Add 3rd Lugo 500/230 kV Transformer;
- Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines;
- Rebuild/build Kramer–Victor 115 kV lines to 230 kV; and
- Loop the old segment of Kramer–Victor 115 kV into Roadway.

The estimated project cost is $482 million and is expected to be in service in 2032.

[61] There were no resources in the portfolio behind this constraint. Per tariff Section 24.xx there was a 53 MW MIC expansion request on Silver Peak branch group.

Figure 3.5-12: Lugo–Victor–Kramer 230 kV Upgrade



The ISO had considered expanding the existing RAS in the area to mitigate the constraints, however it was determined that this was not a valid alternative per the following assessment.

- The area heavily relies on increasingly complex and overlapping RAS to ensure deliverability and reliability of in-development resources and to protect reliability of the system.
- A total of up to about 3,325 MW existing and planned resources will be connected to the NOL area RAS to mitigate deliverability and reliability constraints in the Lugo–Victor–Kramer corridor.
- The planned RAS has already gone beyond the ISO RAS guidelines ISO-G-RAS1 and ISO-G-RAS3 in the ISO Planning Standards, which state that a RAS should be designed for simple operation to trip a fixed set of generation under specific contingencies and the total net amount of generation tripped by a RAS should not exceed 1,150 MW or 1,400 MW depending on the type of contingency.
- The overlapping design of the area RAS is also inconsistent with ISO RAS guideline ISO-G-RAS2 in the ISO Planning Standard.
- Addition of portfolio resources without transmission upgrades is not a valid option and would cause long-term operational complexities and reliability impacts.

The ISO also considered establishing a 500 kV station at Kramer and a 500 kV line Lugo as an alternative to mitigate the constraints. The estimated cost of this alternative is $700 million. While this alternative would provide a higher transfer capability out of the area, the Lugo–Victor–Kramer 230 kV Upgrade provides adequate capacity for the base and sensitivity portfolio as well as the portfolio identified in the ISO 20-Year Transmission Outlook for the area. In addition to the policy benefits which is the basis for recommending this project, the project also provides reliability benefits and production cost savings.

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE North of Lugo interconnection areas along with the recommended mitigation plans are identified in Table 3.5-22.

Table 3.5-22: SCE North of Lugo Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Lugo 500/230 kV Transformers	Base	919	400	368	Transmission identified for on-peak deliverability
	Sensitivity	3,272	1,132	1,594	
Victor–Lugo 230 kV Lines	Base	-	-	0	Not required
	Sensitivity	2,052	692	994	Transmission identified for on-peak deliverability
Kramer–Victor 230 kV	Base	150	150	995	Transmission identified for on-peak deliverability
	Sensitivity	1,588	533	1,600	
Kramer–Sandlot–Coolwater 230 kV	Base	0	0	62	Planned NOL CRAS or energy storage charging
	Sensitivity	0	0	63	
Calcite–Pisgah–Lugo 230 kV corridor	Base	650	250	28	Energy storage charging
	Sensitivity	1,220	440	85	

3.5.7 SCE Metro Interconnection Area

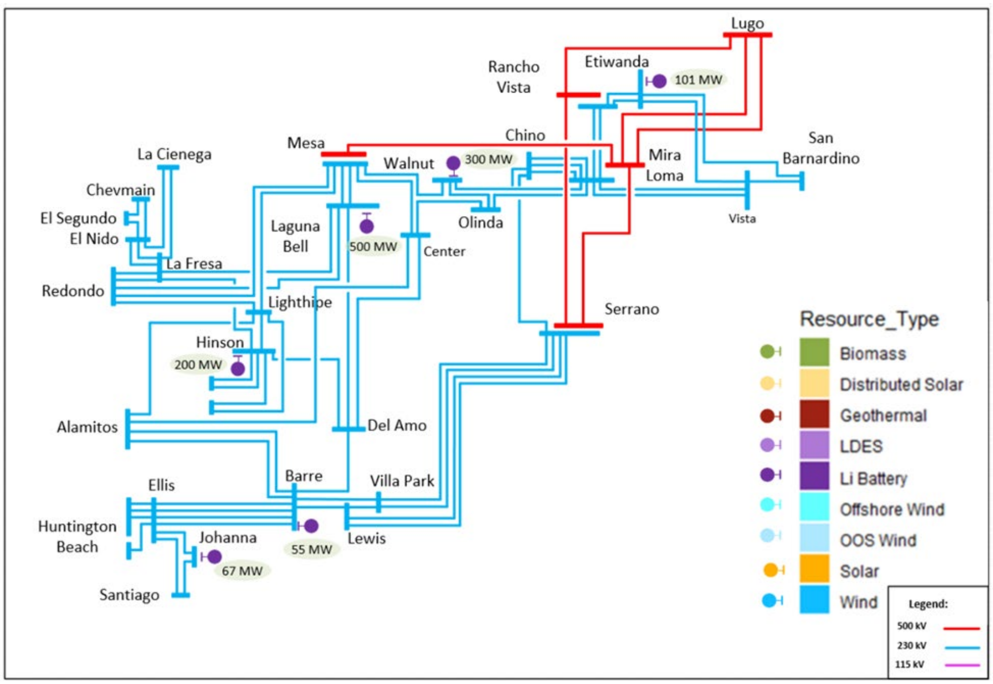
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Metro interconnection area, are listed in Table 3.5-23. The portfolios in the interconnection area are comprised of battery storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-23: SCE Metro Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	-	-		-	-	-
Wind – In State	-	-		-	-	-
Wind – Out-of-State (Existing TX)	-	-		-	-	-
Wind – Out-of-State (New TX)	-	-		-	-	-
Wind – Offshore	-	-		-	-	-
Li Battery	1,161	-	**1,161**	1,605	-	**1,605**
Geothermal	-	-		-	-	-
Long Duration Energy Storage (LDES)	-	-		-	-	-
Biomass/Biogass	-	-		-	-	-
Distributed Solar	-	-		-	-	-
Total	**1,161**	**-**	**1,161**	**1,605**	**-**	**1,605**

The resources as identified in the CPUC busbar mapping for the SCE Metro interconnection area are illustrated on the single-line diagram in Figure 3.5-13.

Figure 3.5-13: SCE Metro Interconnection Area – Mapped[62] Base Portfolio



On-Peak Deliverability

The constraints identified in the on-peak deliverability assessment of the SCE Metro interconnection area along with the recommended mitigation plans are identified in Table 3.5-24.

[62] Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Metro Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

Table 3.5-24: SCE Metro Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
South of Mesa Constraint	Base	-	-	-	0	Not required
	Sensitivity	1,934	1,807	0	2,991	South Area Reinforcement
Serrano-Barre Corridor	Base	-	-	-	0	Not required
	Sensitivity	6,350	3,109	4,712	1,638	South Area Reinforcement
Mesa-Mira Loma 500 kV Line UG Segment	Base	8,917	3,932	8,851	388	Mesa-Mira Loma Underground Third Cable included in the South Area Reinforcement
	Sensitivity	21,160	9,192	18,031	3,451	

Mira Loma-Mesa 500 kV Underground Third Cable

To mitigate the Mesa-Mira Loma 500 kV Line UG Segment constraint, the ISO is recommending the Mira Loma 500 kV Underground Third Cable project. In addition to mitigating the Mesa-Mira Loma 500 kV line UG segment, the project also provides mitigation to the Serano-Alberhill-Valley 500 kV constraint in the SCE Eastern interconnection area identified in Section 3.5.8. The scope of the project is as follows:

- Add a third underground cable on the underground section of the existing Mira Loma-Mesa 500 kV circuit, increasing the rating of the section from 1992 / 3204 MVA (normal/emergency) to 3421 / 4616 MVA (normal/emergency).

The estimated cost for upgrading the Mira Loma-Mesa 500 kV Underground Third Cable is $35 million with an estimated in-service date of 2026.

To mitigate for the constraints in the sensitivity portfolio, in addition to the upgrades identified above, further southern area reinforcements are required. The resources in the portfolio within the SCE Metro, SCE Eastern and SDG&E interconnection area have been assessed together in considering alternatives that mitigate the constraints in the base and sensitivity portfolios for all areas. The recommended alternative of the southern interconnection area is included in San Diego interconnection area assessment in Section 3.5.9.

Off-Peak Deliverability

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE Metro interconnection areas along with the recommended mitigation plans are identified in Table 3.5-25.

Table 3.5-25: SCE Metro Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
South of Mesa Corridor	Base	-	-	0	Not required
	Sensitivity	2,782	1,227	334	Energy storage charging

3.5.8 SCE Eastern Interconnection Area

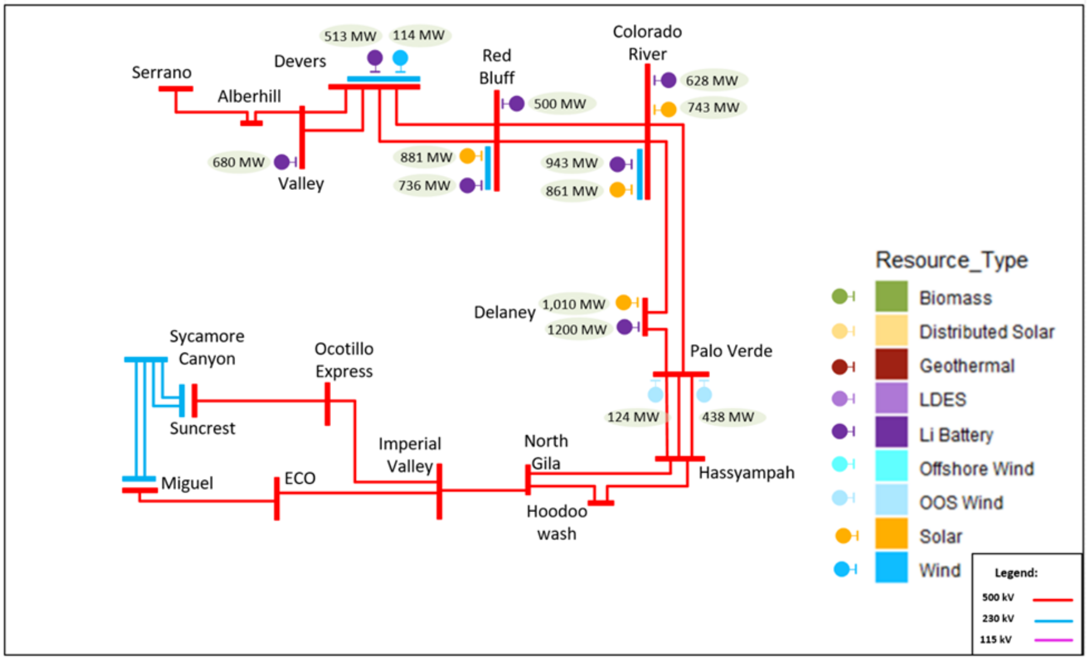
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Eastern interconnection area are listed in Table 3.5-26. The portfolios are comprised of solar, wind (in-state and out-of-state), battery storage and biomass/biogass resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-26: SCE Eastern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	1,262	1,716	**2,978**	2,067	5,250	**7,517**
Wind – In State	106	-	**106**	116	-	**116**
Wind – Out-of-State (Existing TX)	124	-	**124**	124	-	**124**
Wind – Out-of-State (New TX)	438	-	**438**	2,328	-	**2,328**
Wind – Offshore	-	-	**-**	-	-	**-**
Li Battery	2,098	-	**2,098**	5,350	-	**5,350**
Geothermal	-	-	**-**	-	-	**-**
Long Duration Energy Storage (LDES)	-	-	**-**	700	-	**700**
Biomass/Biogass	3	-	**3**	3	-	**3**
Distributed Solar	-	-	**-**	-	-	**-**
Total	**4,031**	**1,716**	**5,747**	**10,687**	**5,250**	**15,937**

The resources as identified in the CPUC busbar mapping for the SCE Eastern interconnection area are illustrated on the single-line diagram in Figure 3.5-13.

Figure 3.5-14: SCE Eastern Interconnection Area – Mapped[63] Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE Eastern interconnection area along with the recommended mitigation plans are identified in Table 3.5-27.

Table 3.5-27: SCE Eastern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Devers-Red Bluff 500 kV	Base	5,821	1,404	0	7,956	Devers-Red Bluff 1 and 2 Upgrade
	Sensitivity	14,739	5002	0	15,033	Base upgrade plus South Area Reinforcement
Serano-Alberhill-Valley 500 kV	Base	2,514	769	0	2,732	Upgrade of 2 – 500 kV lines, 3 – 230 kV lines and adding third underground cable to the existing Mira Loma 500 kV circuit.
	Sensitivity	8,233	2,961	2,952	5,281	Base upgrade
Colorado River-Red Bluff 500 kV	Base	5,821	1,404	4,847	1,150	Colorado River-Red Bluff 1 Upgrade
	Sensitivity	13,221	4,523	11,450	1,972	Devers-Red Bluff 1 and 2 Upgrade
Colorado River 500/230 kV	Base	0	0	-	323	West of Colorado River CRAS
	Sensistivity	371	207	0	465	

[63] Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Eastern Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

Devers-Red Bluff 500 kV 1 and 2 Line Upgrade

To mitigate the Devers-Red Bluff 500 kV constraint in the base portfolio, the ISO is recommending the Devers-Red Bluff 1 and 2 Upgrade project. Increasing the rating of the Devers-Red Bluff No.1 and Devers-Red Bluff No.2 500 kV lines is the first step of transmission upgrades considered to address this constraint. This would maximize the use of existing transmission infrastructure as much as possible. The scope of the project is as follows:

- Increase the rating of the Devers-Red Bluff 500 kV 1 Line from 2598 / 2858 MVA (normal/emergency) to 3291 / 3880 MVA (normal/emergency); and
- Increase the rating of the Devers-Red Bluff 500 kV 2 Line from 2598 / 2910 MVA (normal/emergency) to 3291 / 3880 MVA (normal/emergency).

The estimated cost for upgrading the Devers-Red Bluff 500 kV 1 and 2 Line is $140 million with an expected in-service date of 2028.

Colorado River-Red Bluff 500 kV 1 Line Upgrade

To mitigate the Coloardo River-Red Bluff 500 kV constraint, the ISO recommends approval of the following project. The scope of the Colorado River-Red Bluff 500 kV 1 Line Upgrade project is as follows:

- Increase the line rating from 2338 / 2858 MVA (normal/emergency) to 3421 / 3880 MVA (normal/emergency).

The estimated cost for upgrading the Colorado River-Red Bluff 500 kV 1 Line Upgrade is $50 million with an estimated in-service date of 2028.

To mitigate the Serano-Alberhill-Valley 500 kV constraint the ISO recommends approval of the following 6 upgrade projects.

Devers-Valley 500 kV 1 Line Upgrade

The scope of the Devers-Valley 500 kV 1 Line Upgrade project is as follows:

- Increase the line rating from 2598 / 2858 MVA (normal/emergency) to 3421 / 3880 MVA (normal/emergency).

The estimated cost for upgrading the Devers-Valley 500 kV 1 Line Upgrade is $45 million with an estimated in-service date off 2028.

Serrano-Alberhill-Valley 500 kV 1 Line Upgrade

The scope of the Serrano-Alberhill-Valley 500 kV 1 Line Upgrade project is as follows:

- Increase the line rating of the Serrano-Alberhill 500 kV 1 Line from 2598 / 4157 MVA (normal/emergency) to 3421 / 4157 MVA (normal/emergency); and
- Increase the line rating of the Alberhill-Valley 500 kV 1 Line from 2598 / 4157 MVA (normal/emergency) to 3421 / 4416 MVA (normal/emergency).

The estimated cost for upgrading the Serrano-Alberhill-Valley 500 kV 1 Line Upgrade is $60 million with an estimated in-service date of 2028.

San Bernardino-Etiwanda 230 kV 1 Line Upgrade

The scope of the San Bernardino-Etiwanda 230 kV 1 Line Upgrade project is as follows:

- Increase the line rating of the San Bernardino-Etiwanda 230 kV 1 Line from 988 / 1040 MVA (normal/emergency) to 1287 / 1737 MVA (normal/emergency).

The estimated cost for upgrading the San Bernardino-Etiwanda 230 kV 1 Line Upgrade project is $65 million with an estimated in-service date of 2031.

San Bernardino-Vista 230 kV 1 Line Upgrade

The scope of the San Bernardino-Vista 230 kV 1 Line Upgrade project is as follows:

- Increase the line rating of the San Bernardino-Vista 230 kV 1 line from 988 / 1331 MVA (normal/emergency) to 1287 / 1737 MVA (normal/emergency).

The estimated cost for upgrading the San Bernardino-Vista No.1 230 kV line Upgrade is $18 million with an estimated in-service date of 2026.

Vista-Etiwanda 230 kV 1 Line Upgrade

The scope of the Vista-Etiwanda 230 kV 1 Line Upgrade project is as follows:

- Increase the line rating of the Vista-Etiwanda 230 kV 1 Line from 797 / 876 MVA (normal/emergency) to 988 / 1331 MVA (normal/emergency).

The estimated cost for upgrading the Vista-Etiwanda No.1 230 kV line Upgrade is $13 million with an estimated in-service date off 2031.

Mira Loma-Mesa 500 kV Underground Third Cable

The Mira Loma-Mesa 500 kV Underground Third Cable project recommended for approval in the Metro interconnection area On-peak deliverability assessment in Section 3.5.7 is also required to mitigate the Serano-Alberhill-Valley 500 kV constraint.

To mitigate for the constraint in the sensitivity portfolio, in addition to the upgrades identified above, further southern area reinforcements are required. The resources in the portfolio within the SCE Metro, SCE Eastern and SDG&E interconnection area have been assessed together in considering alternatives that mitigate the constraints in the base and sensitivity portfolios for all areas. The recommended alternative of the southern interconnection area is included in San Diego interconnection area assessment in Section 3.5.9.

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE Eastern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-28.

Table 3.5-28: SCE Eastern Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Devers-Red Bluff 500 kV	Base	8,290	1,404	1,187	See SCE Eastern area On-Peak mitigation
	Sensitivity	23,391	5,702	6,137	
Serano-Alberhill-Valley 500 kV	Base	-	-	-	None required
	Sensitivity	13,686	3,661	1,541	See SCE Eastern area On-Peak mitigation
Colorado River 500/230 kV Transformers	Base	0	0	254	West of Colorado River CRAS and/or batteries in charging mode
	Sensitivity	986	207	1,038	
Red Bluff 500/230 kV Transformers	Base	0	0	140	West of Colorado River CRAS
	Sensistivity	894	78	940	

3.5.9 SDG&E Interconnection Area

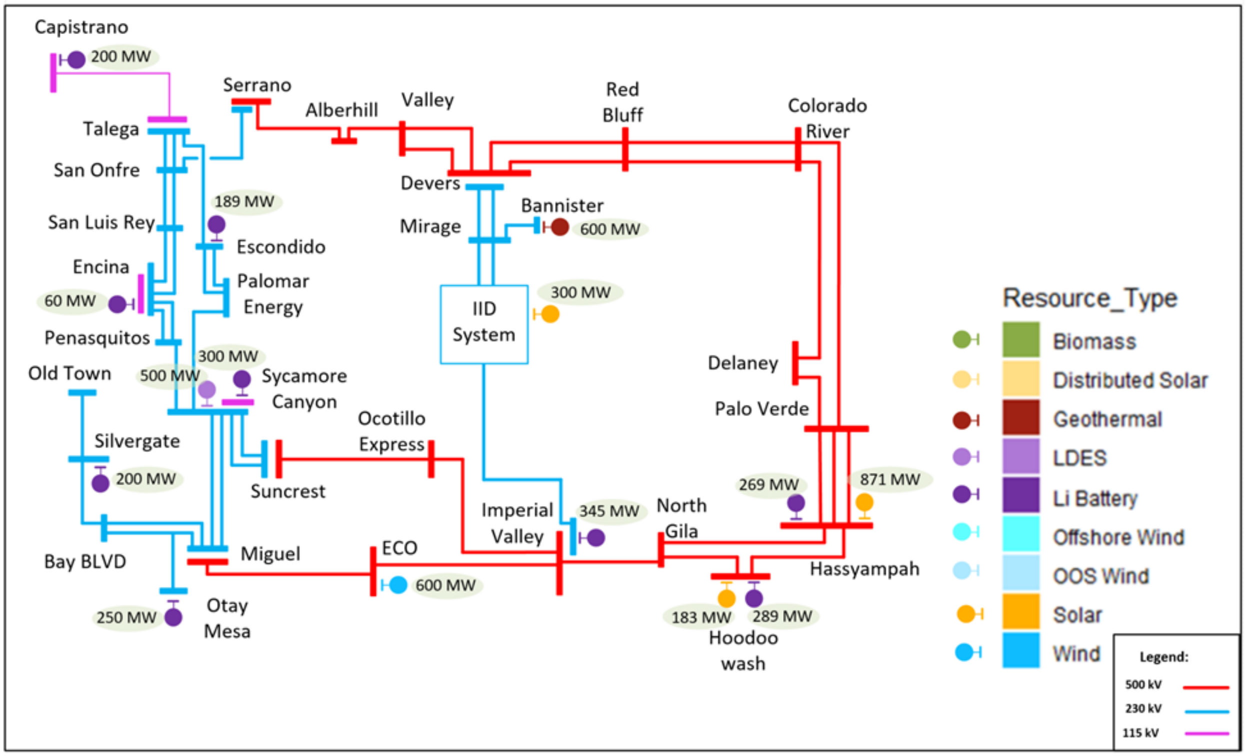
Table 3.5-29 includes the total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SDG&E interconnection area. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery storage, geothermal, and long duration energy storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-29: SDG&E Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	300	871	**1,171**	484	1,390	**1,874**
Wind – In State	600	-	**600**	600	-	**600**
Wind – Out-of-State (Existing TX)	-	-	**-**	-	-	**-**
Wind – Out-of-State (New TX)	-	-	**-**	-	-	**-**
Wind – Offshore	-	-	**-**	-	-	**-**
Li Battery	1,418	-	**1,418**	2,527	-	**2,527**
Geothermal	600	-	**600**	900	-	**900**
Long Duration Energy Storage (LDES)	500	-	**500**	500	-	**500**
Biomass/Biogass	-	-	**-**	-	-	**-**
Distributed Solar	-	-	**-**	-	-	**-**
Total	**3,418**	**871**	**4,289**	**5,011**	**1,390**	**6,401**

The resources as identified in the CPUC busbar mapping for the SDG&E interconnection area are illustrated on the single-line diagram in Figure 3.5-14.

Figure 3.5-15: SDG&E Interconnection Area – Mapped[64] Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SDG&E interconnection area along with the recommended mitigation plans are identified in Table 3.5-30.

Table 3.5-30: SDG&E Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
East of Miguel	Base	1,178	279	0	3,080	Southern area reinforcement
	Sensitivity	5,834	2,173	0	10,398	
Bay Boulevard-Silvergate	Base	1,209	10	0	2,373	2 hour emergency rating on Silvergate-Bay Boulevard 230 kV line and south area reinforcement
	Sensitivity	1,676	475	0	3,408	
Encina-San Luis Rey	Base	1,958	510	0	2,776	30 minute emergency rating on Encina Tap-San Luis
	Sensitivity	3,260	1,808	2,765	1,422	

64 Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SDG&E Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

						Rey 230 kV Line and south area reinforcement
Sycamore Area	Base	1,509	310	1,030	680	30 min emergency rating for Sycamore-Scripps 69 kV line upgrade Sycamore-Chicarita 138 kV, new 3 ohm reactor on Sycamore-Penasquitos 230 kV and South area reinforcement
	Sensistivity	2,716	1,264	1,314	2,329	
San Luis Rey-San Onofre	Base	2,427	1,028	0	3,454	South area reinforcement
	Sensistivity	3,625	2,037	3,801	1,120	
Silvergate-Old Town	Base	909	210	0	1,944	Use 30 min emergency rating for Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines and South area reinforcement
	Sensitivity	1,376	675	0	2,466	
Friars-Doublet Tap	Base	500	500	0	1,339	SDGE Project Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento
	Sensitivity	2,155	1,055	0	2,604	
San Marcos-Melrose Tap	Base	1,189	689	0	1,784	Reconductor TLC680C San Marcos-Melrose Tap
	Sensitivity	2,279	1,179	797	1,482	

The following projects have been identified as required to address the local SDG&E constraints from the On-peak delivability assessment.

Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento

To address the Friars-Doublet Tap constraint identified in the base and sensitivity portfolios, the ISO recommends the approval of the Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento projectFigure 3.5-12. The scope of the project is as follow:

- Swap TL23013 Penasquitos-Old Town with TL6959 Penasquitos-Mira Sorrento so that TL23013 & TL23071 will not share same Structures (TL23071 sharing structures withTL6959 and TL23013 sharing structures with TL13810). This proposal will require to upgrade 2 miles of 138 kV structures for 230 kV operation.

The estimated project cost is between $19 to $21 million and is expected to be in-service in 2032.

Reconductor TL680C San Marcos-Melrose Tap

To address the San Marcos-Melrose Tap constraint identified in the base and sensitivity portfolios, the ISO recommends the approval of the Reconductor TL680C San Marcos-Melrose Tap project. The scope of the project is as follow.

- Reconductor San Marcos-Melrose Tap 69 kV line to 250 MVA.

The estimated project cost is $28 million and is expected to be in service in 2032.

3 ohm series reactor on Sycamore-Penasquitos 230 kV Line

To address the Sycamore Area constraint identified in the base and sensitivity portfolios, the ISO recommends the approval of the 3 ohm series reactor on Sycamore-Penasquitos 230 kV Line project. The scope of the project is as follow.

- • Install 3 ohm series reactor on Sycamore-Penasquitos 230 kV Line

The estimated project cost is $8 million and is expected to be in service in 2032.

Upgrade TL13820 Sycamore-Chicarita 138 kV

To address the Sycamore Area constraint identified in the base and sensitivity portfolios, the ISO recommends the approval of the Upgrade TL13820 Sycamore-Chicarita 138 kV project. The scope of the project is as follow:

- Reconductor Sycamore-Chicarita 138 kV line to 250 MVA

The estimated project cost is $60 million and is expected to be in service in 2032.

In addition to the above projects recommended for approval, the following would be required as a part of the mitigation plan:

- Existing Miguel banks RAS;
- CEC RAS, under construction. Trip gen at Encina for P1 outages of Encina-San Luis Rey 230 kV or Encina-San Luis Rey-Palomar 230 kV;
- Use 2 hour emergency rating for Silvergate-Bay Boulevard 230 kV line;
- Use 30 min emergency rating for Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines;
- Use 30 min emergency rating for Encina Tap-San Luis Rey 230 kV line;
- Use 30 min emergency rating for San Luis Rey-San Onofre 230 kV #1 line; and
- Use 30 min emergency rating for Sycamore-Scripps 69 kV line

In addition to the upgrades identified in the SCE Mesa (Section 3.5.7) and the SCE Eastern (Section 3.5.8) interconnection area On-peak deliverability assessment, further southern area reinforcements are required. The resources in the portfolio within the SCE Metro, SCE Eastern and SDG&E interconnection area have been assessed together in considering alternatives that mitigate the constraints in the base and sensitivity portfolios for all areas. To address the East of Miguel, Bay Boulevard-Silvergate, Encina-San Luis Rey, Sycamore area, San Luis Rey-San Onofre, and Silvergate-Old Town constraints identified in the base and sensitivity portfolios, the ISO is recommending the following projects identified in the southern area reinforcement as follows.

<u>Southern Area Reinforcement</u>

<u>Imperial Valley–North of SONGS 500 kV Line and Substation</u>

The ISO is recommending the Imperial Valley–North of SONGS 500 kV Line and Substation project as a part of the south area reinforcement. The scope of the project is as follows:

- New Imperial Valley–N.SONGS 500 kV line, estimated at 145 miles, with 50% series compensation;
- New 500/230 kV Substation north of SONGS complete with three (3) 500/230 kV transformers; and
- Loop the San Onofre–Santiago 230 kV 1 and 2 lines and the San Onofre–Viejo 230 kV line into the new substation.

The estimated project cost is $2,288 million and is expected to be in service by 2034.

<u>North of SONGS–Serrano 500 kV Line</u>

The ISO is recommending the North of SONGS–Serrano 500 kV AC Line project as a part of the south area reinforcement. The scope of the project is as follows:

- North of SONGS–Serrano 500 kV AC line, estimated at 30 miles.

The estimated project cost is between $503 million and is expected to be in-service by 2034.

<u>Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement</u>

The ISO is recommending the Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement project as a part of the south area reinforcement. The scope of the project is as follows:

- New 500 kV switchyard at Del Amo complete with three (3) 500/230 kV transformers;
- Utilize the existing conductor on Mesa-Mira Loma 500 kV line and build approximately a 2-mile new section into Mesa and an approximately 13-mile new 500 kV line to Serrano;
- Interconnect the new Mesa-Serrano 500 kV line with 2 new 500 kV lines from Del Amo (approximately 13 miles) to form the Del Amo-Mesa and Del Amo-Serrano 500 kV lines; and
- Loop Alamitos–Barre No. 1 and No. 2 230 kV lines into Del Amo Substation.

The estimated project cost is between $1,125 million and is expected to be in-service by 2033.

<u>North Gila-Imperial Valley 500 kV Transmission Line</u>

The ISO is recommending the North Gila-Imperial Valley 500 kV Transmission Line project as a part of the south area reinforcement. The scope of the project is as follows:

- A new North Gila–Imperial Valley 500 kV line,[65] estimated at approximately 97 miles.

[65] An economic study request was submitted for a joint project with IID to for a 500 kV line from North Gila-Imperial Valley with a new 500 kV switchyard at IID Highline Substation and one (1) 500/230 kV transformer. The ISO is continuing to explore a potential joint project with IID.

The estimated project cost is $340 million and is expected to be in service in 2032.

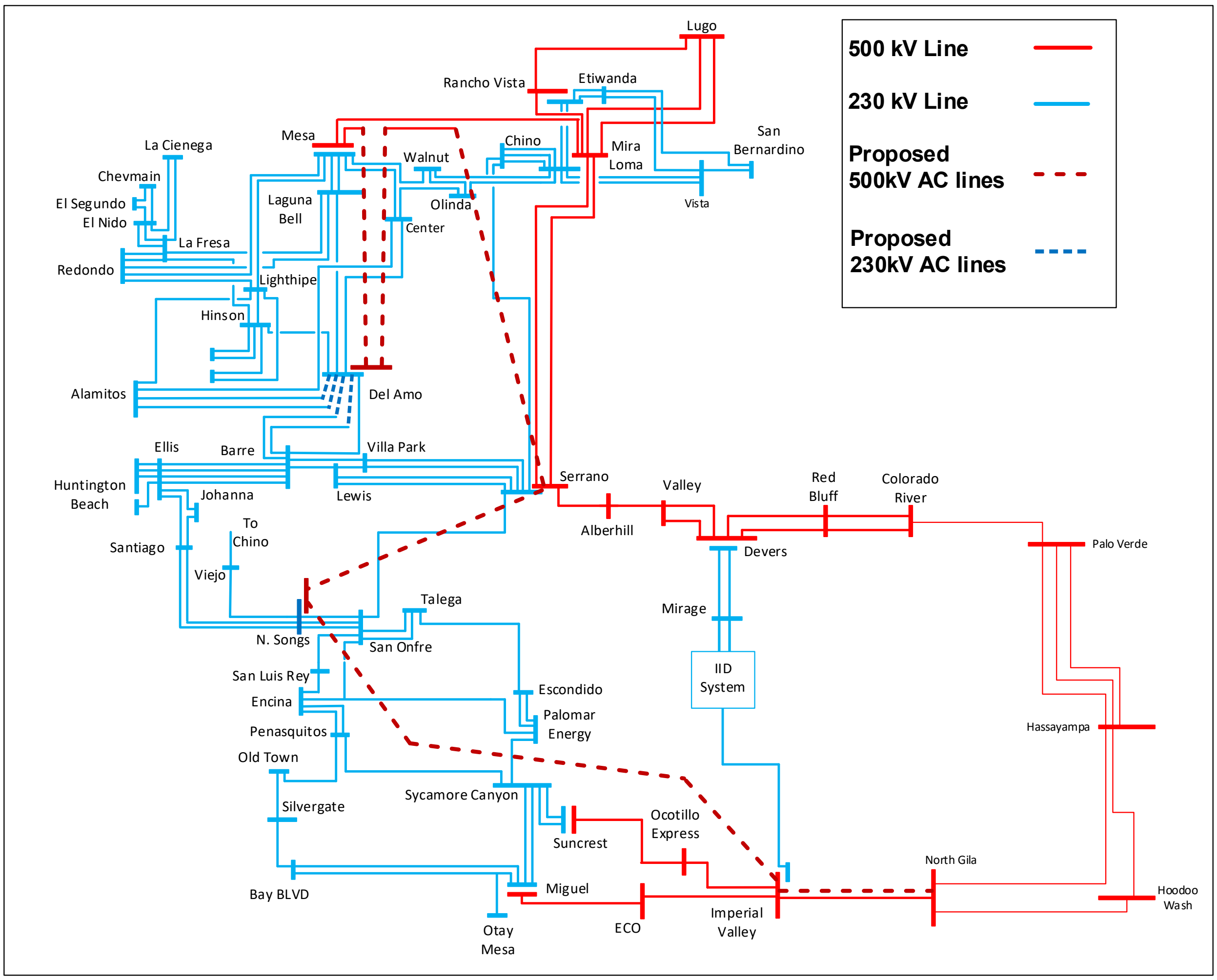
Upgrade on Hoodoo Wash-North Gila and Hassayampa-North Gila Transmission Lines

The ISO is recommending to upgrade the Hoodoo Wash-North Gila and Hassayampa-North Gila transmission lines and their series compensation as a part of the south area reinforcement. These upgrades are to the Arizona Public Service (APS) neighboring system equipment upgrades as an affected system, and to the SDG&E system. [66] For the APS portions, the ISO has voluntarily agreed, as set out in Section 24.10 of the ISO tariff, to the cost of the upgrades to limiting equipment. The scope of the project is as follows:

- Upgrade the Hoodoo Wash-North Gila and Hassayampa-North Gila 500 kV lines and series capacitors to 3250 Amps emergency rating.

The estimated project cost is $27 million and is expected to be in service in 2032.

Figure 3.5-16: South Area Reinforcement Projects



[66] The Hoodoo Wash-North Gila Line is owned by SDG&E, APS, and IID. The Hassayampa-North Gila line is owned by APS and IID. APS is the planning, design, construction and maintenance company for the Hoodoo Wash-North Gila line. APS has all the responsibilities for the Hassayampa-North Gila line.

The ISO considered a number of transmission development alternatives for the south area reinforcements in Appendix F. The following are the alternative developments.

- North Gila–Imperial Valley–Inland–Serrano–Del Amo–Mesa 500 kV AC Development.
    - Creating the 230 kV North of SONGS provides better technical performance and avoids having to rebuild the 230 kV lines between Talega and Escondido.
- North Gila–Imperial Valley AC & Imperial Valley–Inland–Del Amo 500 kV HVDC Development.
    - HVDC projects provide opportunity if undergrounding of sections is required and additional flow control on path; however cost is approximately $2,000 million more.
- North Gila–Imperial Valley–North of SONGS AC and North of SONGS–Del Amo HVDC 500 kV Development.
    - HVDC projects provide opportunity if undergrounding of sections is required and additional flow control on path; however cost is approximately $2,000 million more.
    - Limited land available, other within existing SCE land, at Del Amo for an HVDC converter station.
- North Gila–Imperial Valley–Inland AC and Inland–Del Amo HVDC 500 kV Development.
    - HVDC projects provide opportunity if undergrounding of sections is required and additional flow control on path; however cost is approximately $2,000 million more.
- North Gila–Imperial Valley–Suncrest and Red Bluff–Devers–Mira Loma 500 kV Development.
    - Alternative is approximately $2,000 million more.

Off-Peak Deliverability Assessment

The Off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SDG&E interconnection areas along with the recommended mitigation plans are identified in Table 3.5-31.

Table 3.5-31: SDG&E Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
East of Miguel	Base	2,781	769	1,956	On-peak mitigation
	Sensitivity	4,479	2,173	3,833	

3.6 Out-of-State Wind

The base portfolio includes 1,500 MW of out-of-state wind resources (1,062 MW from Wyoming or Idaho and 438 MW from New Mexico) and the sensitivity portfolio includes 4,832 MW (1,500 MW from Wyoming, 1,000 MW from Idaho and 2,328 MW from New Mexico). These resources have been identified by CPUC as requiring new transmission and have been included in the policy analysis and alternative analysis as expanding the maximum import capability of the paths to import the out-of-state wind to determine the CAISO internal transmission needs required to accommodate the out-of-state wind identified. Further, the ISO also notes that the base portfolio for the 2023-2024 transmission plan reflects the same volumes and sources of out-of-state wind as this year's sensitivity.[67]

Two out-of-state subscriber transmission developments to accommodate the wind resources in Wyoming (TransWest Express) and New Mexico (Sunzia) are currently underway.

The ISO is continuing to assess the SWIP North project proposed by LS Power for accessing wind resources in Idaho given the resource portfolios being studied in this year's planning analysis and the base portfolio for the 2023-2024 Transmission Plan. The ISO's economic studies also demonstrate other economic benefits contributing to the overall value provided by the project, as set out in Chapter 4. Idaho Power has expressed interest in the SWIP North project and the ISO has initiated discussions with Idaho Power about joint participation. Idaho Power has expressed an interest in South to North capacity, though potentially not for the full 1,000 MW of capability. The ISO notes there may be opportunities for DOE funding for unutilized capacity that the ISO is currently exploring. Idaho Power is currently performing a detailed analysis of the SWIP North project in its 2023 IRP which will be filed with its Public Utilities Commission by September 30th. The filing, originally planned for June, had to be extended due to the nature of analysis being performed.

The SWIP North project does not meet the criteria defining interregional transmission projects, as set out in the ISO's tariff. Accordingly, the ISO intends to work with Idaho Power and other potential interested transmission service providers and continue the development of a recommendation for the SWIP North project, as a potential regional policy-driven project. This will be conducted as an extension to this planning cycle.

Both the SWIP North project and the TransWest Express project would deliver significant quantities of out-of-state wind into the Harry Allen-Eldorado area, and the combined impact on existing WECC Paths in the area will need to be addressed.

3.7 Offshore Wind

In the Morro Bay area, the base portfolio included 1,588 MW and the sensitivity portfolio included 3,100 MW of offshore wind. For the interconnection of the offshore wind, the existing Diablo 500 kV substation has been identified and is where current offshore wind interconnection requests in the ISO queue are primarily located. The ISO has also considered the alternative of creating a new 500 kV substation on the Diablo-Gates 500 kV for the interconnection of the

[67] CPUC Decision (D.) 23-02-040 adopted on February 23, 2023.

Morro Bay area offshore wind. The ISO will continue to coordinate with PG&E and the offshore resource developers, which were the successful federal Bureau of Ocean Energy Management (BOEM) lease bidders, for the interconnection point for the Morro Bay area offshore wind.

The base resource portfolio provided by the CPUC for the 2022-2023 Transmission Plan does not support the need for transmission capacity from the North Coast in this year's studies, with 100-150 MW of offshore wind mapped to the Humboldt area. The need for new transmission from the North Coast area was identified in studying the sensitivity portfolio. The ISO also notes that the base portfolio for the 2023-2024 transmission plan will necessitate new transmission, with 1.6 GW of offshore wind mapped to the north coast/Humboldt area.[68]

Given the resource portfolios provided for this year's transmission planning studies and the state's progress of resource development planning activities (supply chains, harbors, etc.) with the CEC AB 525 report due in June 2023, the ISO is not recommending approval of transmission solutions in this planning cycle and will look instead to advancing upgrades in the next planning cycle. The assessment of alternatives in this planning cycle was conducted on the sensitivity portfolio and documented in Appendix F and will assist in being positioned to make a decision for the recommended transmission for the North Coast in the 2023-2024 Transmission Plan.

3.8 CPUC Request to CAISO in Accordance with SB 887

The CPUC submitted a letter[69] to the ISO on January 13, 2023 in accordance with SB 887 indicating the following.

> *"Pursuant to Senate Bill 887 (Becker, 2022), this letter requests the California Independent System Operator to (1) identify, based as much as possible on studies and projections completed before January 1, 2023, by the CAISO, the CPUC and the California Energy Commission, the highest priority transmission facilities that are needed to allow for increased transmission capacity into local capacity areas to deliver renewable energy resources or zero-carbon resources that are expected to be developed by 2035, and (2) consider whether to approve such transmission projects as part of the CAISO's 2022–23 transmission planning process."*

The ISO addressed this request, by considering the following sources of relevant information:

- The two-year study process conducted through the 2018-2019 and the 2019-2020 transmission plan specifically undertaken to explore options and opportunities to reduce reliance on – primarily gas-fired – local capacity requirements in the ISO's local capacity areas and sub-areas. That work specifically prioritized areas relying on natural gas and/or petroleum, risk of retirement, and proximity to disadvantaged communities;
- Economic planning studies conducted in the 2020-2021 Transmission Plan (where detailed economic studies explored reducing local capacity requirements in the Greater

[68] CPUC Decision (D.) 23-02-040 adopted on February 23, 2023.

[69] http://www.caiso.com/InitiativeDocuments/Letter-2022-2023-Transmission-Planning-Process-Jan%2013,%202023.pdf

Bay area, the LA Basin area and the Big Creek-Ventura area, but no projects were recommended for approval);

- Economic planning studies conducted in 2021-2022 Transmission Plan (where the Pacific Transmission Expansion Project was studied to alleviate Path 26 congestion as well as capture the previously studied benefits in reducing local capacity requirements in the LA Basin area and the Big Creek-Ventura area); and
- The ISO's 20 Year Transmission Outlook released May, 2022.

As noted throughout the ISO's past studies of local capacity requirement reduction opportunities, the study results and corresponding conclusions are heavily influenced, in particular, by the longer term requirements for gas-fired generation for system and flexible capacity requirements The uncertainty regarding the extent to which gas-fired generation will be needed to meet those system and flexible capacity requirements necessitated taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements. The CAISO accordingly has placed values on benefits associated with reducing local gas-fired generation capacity requirements primarily on the difference between the relevant local area capacity price and system capacity prices. This reflects the economic capacity benefit of less generation being needed for local capacity even if it is still needed for system capacity. This conservative assumption was a key difference between the economic benefits calculated in this study, and the economic assessments stakeholders provided in support of their proposed projects. The CAISO recognizes that the capacity value of many of these projects will need to be revised when actionable direction on the need for gas-fired generation for system and flexible needs is available. As noted in Chapter 1, SB 887[70] calls for the CPUC to provide to the ISO by March 31, 2024, resource projections that are expected to reduce by 2035 the need to rely on non-preferred resources in local capacity areas, however these projections are not yet reflected in the portfolios provided by the CPUC for the 2022-2023 Plan.

The ISO then considered these inputs in developing its recommendations in this 2022-2023 Transmission Plan. In this Plan, the ISO has assessed the potential to advance additional projects beyond those approved in this plan to allow for increased capacity into local capacity areas to deliver renewable energy resources expected to be developed by 2035. There are 12 projects recommended for approval as reliability-driven and policy-driven that will increase the transmission capability into local areas. The needs for these projects are to meet identified reliability needs or to provide deliverability for the base and sensitivity resource portfolios. These projects are as follows:

- Metcalf 230/115 kV Transformers Circuit Breaker Addition project (reliability-driven) – Section 2. This project is recommended to address reliability needs in the Greater Bay area. This project, along with the two HVDC projects in the San Jose area in the 2021-

[70] SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

2022 Transmission Plan will reduce the local capacity requirements within the San Jose LCR sub-area;

- The seven recommended upgrades to four existing 500 kV lines and three 230 kV lines in the SCE Eastern area (Section 3.5.8) and the addition of the third cable addition to the Mesa-Mira Loma 500 kV underground section (Section 3.5.7) will increase the 500 kV and 230 kV supply to the LA Basin area; and
- The three southern area reinforcement projects (the Imperial Valley–North of SONGS 500 kV Line and Substation, North of SONGS–Serrano 500 kV Line, and Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement projects) will increase the transmission capacity in the LA Basin by establishing a 500 kV source at the existing Del Amo 230 kV substation, and in the San Diego and LA Basin local capacity areas by establishing a new 500 kV source north of San Diego.

The ISO has also reviewed the Pacific Transmission Expansion Project that has been submitted into the Economic Request window in the 2022-2023 transmission planning process. This proposed project is a multi-terminal HVDC project from Diablo Canyon 500 kV substation to multiple 230 kV substations in the LA Basin area. The ISO has been in discussion with LADWP as to its potential interest in project and the possibilities of a joint project; however the ISO is not aware of any decisions by LADWP to move forward at this time[71]. The project can provide improved access to future offshore wind development, offload congestion on Path 26, and reduce gas-fired generation local capacity requirements. However, an ISO recommendation to approve this project will ultimately depend heavily upon the pace and volume of gas-fired generation retirements planned in the LA Basin. The ISO will continue to explore gas-fired generation retirement plans with the CPUC and work with LADWP on potential collaboration opportunities after the Plan has been approved.

3.9 Conclusion and Recommendations

The policy assessment has identified 22 new policy-driven projects recommended for approval in this transmission planning cycle for a total estimated cost of $7.53 billion as listed in Table 3.9-1.

[71] In the LADWP Power System Strategic Transmission Plan update presentation (dated December 13, 2022), LADWP identifies a potential submarine project from the Diablo Canyon area to the LA Basin area and identifies the next steps being to seek collaboration on potential joint transmission projects.

Table 3.9-1: Recommended Policy-Driven Transmission Projects for Approval

No.	Project Name	PTO Area	Planning Area	Cost ($M)	
1	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	Fresno	25	50
2	Henrietta 230/115 kV Bank 3 Replacement	PG&E	Fresno	12	20
3	Beatty 230 kV	VEA/GLW	East of Pisgah	155	155
4	Trout Canyon0Lugo 500 kV Line	GLW/SCE	East of Pisgah	1,500	2,000
5	Lugo–Victor–Kramer 230 kV Upgrade	SCE	North of Lugo	482	482
6	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	SCE Eastern	50	50
7	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	SCE Eastern	140	140
8	Devers-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	40	40
9	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	60	60
10	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	SCe Eastern	65	65
11	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE	SCE Eastern	18	18
12	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	SCE Eastern	13	13
13	Mira Loma-Mesa 500 kV Underground Third Cable	SCE	SCE Metro	35	35
14	Imperial Valley–North of SONGS 500 kV Line and Substation	SDG&E	SDG&E	2,288	2,288
15	North of SONGS–Serrano 500 kV line	SDG&E / SCE	SDG&E and SCE Metro	503	503
16	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE	SCE Metro	1,125	1,125
17	North Gila–Imperial Valley 500 kV line	SDG&E	SDG&E (Potential Joint Project with IID)	340	340
18	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	APS	27	27
19	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	SDG&E	21	21
20	Reconductor TL680C San Marcos-Melrose Tap	SDG&E	SDG&E	28	28
21	3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	SDG&E	8	8
22	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	SDG&E	60	60
			Total	**6,995**	**7,528**

As well, the ISO will conduct additional stakeholder and market outreach regarding the SWIP North project, to refine its recommendation regarding the SWIP North project proposed by LS Power to access Idaho wind resources as a potential regional policy-driven transmission project, taking into account participation interest of neighboring transmission service providers. This work will be conducted as an extension of the 2022-2023 Transmission Plan, seeking Board of Governor approval at a later date.

Chapter 4

4 Economic Planning Study

4.1 Introduction

The ISO's economic planning study is an integral part of the ISO's transmission planning process and is performed on an annual basis as part of the transmission plan. The economic planning study complements the reliability-driven and policy-driven analysis documented in this transmission plan, exploring economic-driven transmission solutions that may create opportunities to reduce ratepayer costs within the ISO.

Each cycle's study is performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan.

The studies used a production cost simulation as the primary tool to identify potential study areas, prioritize study efforts, and to assess benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The production cost simulation is conducted for all hours for each study year.

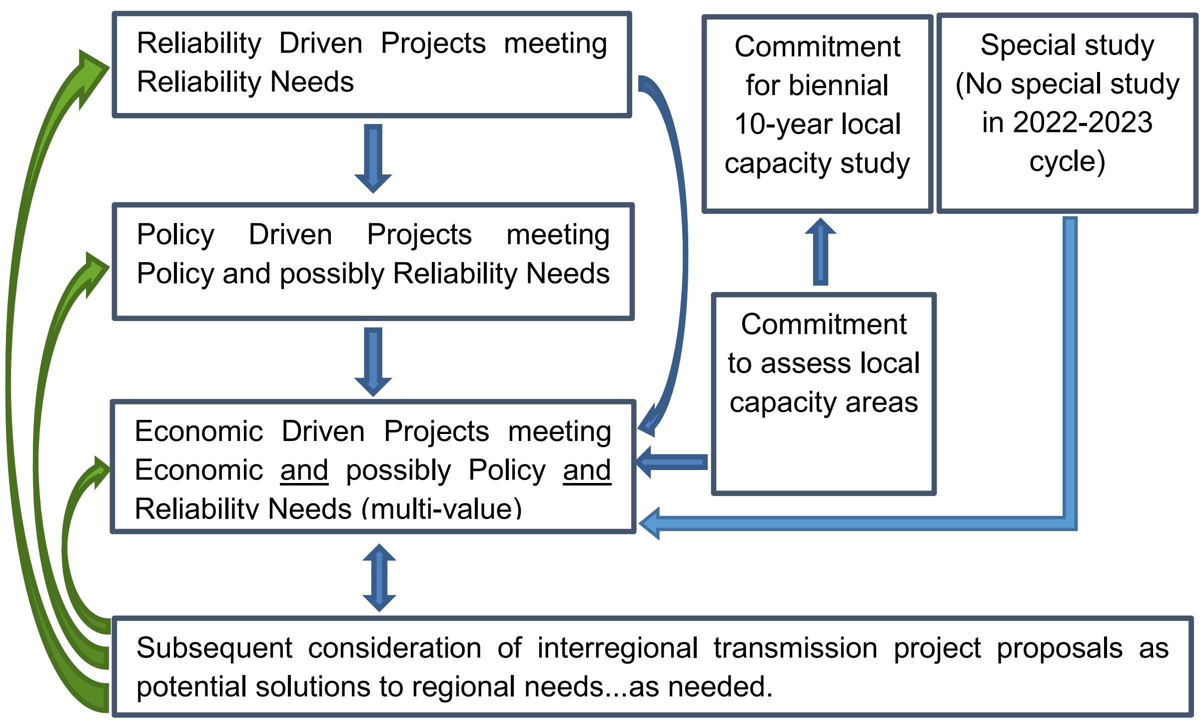
Economic study requirements are being driven from a growing number of sources and needs, including:

- The ISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling;
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified in reliability analyses or to meet local capacity deficiencies;
- An "economic-driven" transmission solution may be upsizing a previously identified reliability solution, or replacing that solution with a different project;
- Opportunities to reduce the cost of local capacity requirements (LCR) – considering capacity costs in particular; and
- Considering interregional transmission projects as potential alternatives to regional solutions to regional needs.

All transmission solutions identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the production cost simulation database. The ISO then performed the economic planning study to identify additional cost-effective transmission solutions to mitigate grid congestion and increase production efficiency within the ISO. These more comprehensive economic studies can also lead to replacing or upscaling a solution initially identified at the reliability or policy stage. The analysis focuses on reducing costs to ISO ratepayers; the potential economic benefits are quantified as reductions of ratepayer costs based on the ISO's documented Transmission Economic Analysis Methodology (TEAM).[72]

The above issues led to requiring a broader view of economic study methodologies and developing stronger interrelationships between studies conducted under different aspects of the transmission planning process. These interrelationships are captured to some extent in Figure 4.1-1.

Figure 4.1-1: Interrelationship of Transmission Planning Studies



The production cost modeling simulations focus primarily on the benefits of alleviating transmission congestion to reduce energy costs. Other benefits are also taken into account where warranted, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven. Local capacity benefits, *e.g.* reducing the requirement for local – and often gas-fired – generation capacity due to limited transmission capacity into an area can also be assessed and generally rely on power flow analysis.

[72] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

4.2 Technical Study Approach and Process

Different components of ISO ratepayer benefits are assessed and quantified under the economic planning study.

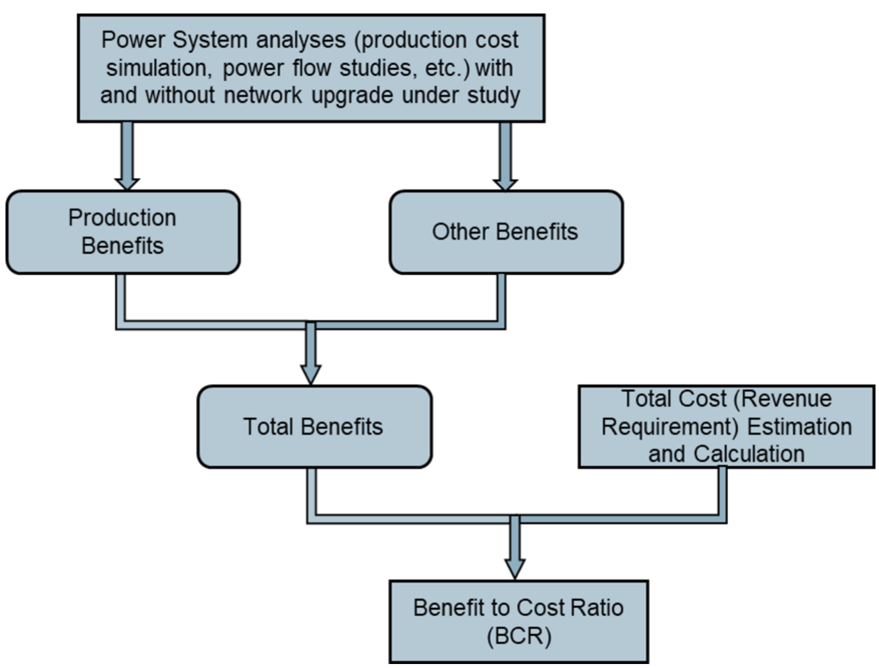
First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the "pre-project" and "post-project" study results, production benefits can be calculated from savings of production costs or ratepayer payments. These include: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues.

Additionally, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings, assessed through power flow analysis. The system RA benefit corresponds to a situation where a transmission solution for importing energy leads to a reduction of ISO system resource requirements, provided that out-of-state resources are less expensive to procure than in-state resources. The local capacity benefit corresponds to a situation where a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource.

Once the total economic benefit is calculated, the benefit is weighed against the cost, which is the total revenue requirement of the project under study.

The technical approach of the economic planning study is depicted in Figure 4.2-1.

Figure 4.2-1: Technical approach of economic planning study



4.3 Cost-Benefit Analysis

A cost-benefit analysis is made for each economic planning study performed where the total costs are weighed against the total benefits of the potential transmission solutions. In these studies, all costs and benefits are expressed in 2022 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net-present values.

In these studies, the “total cost” is considered to be the present value of the annualized revenue requirement in the proposed operation year. The total revenue requirement includes impacts of capital cost, tax expenses, O&M expenses and other relevant costs, using the financial parameters and assumptions set out in Appendix G. The net present value of the costs (and benefits) is calculated using a social discount rate of 7% (real) with sensitivities at 5% as needed.

In the initial planning stage, detailed cash-flow information is typically not provided with the proposed network upgrade to be studied. Instead, lump-sum capital-cost estimates are provided. The ISO then uses typical financial information to determine annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. For screening purposes, the multiplier of 1.3 is used in this study to estimate the present value of the annual revenue requirement stemming from a capital investment, reflective of a 7% real discount rate and based on 40 to 50-year lifespans.

As the “capital cost to revenue requirement” multiplier was developed on the basis of the long lives associated with transmission lines, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values can be developed for battery storage capital costs and can then be compared to the annual benefits identified for those projects.

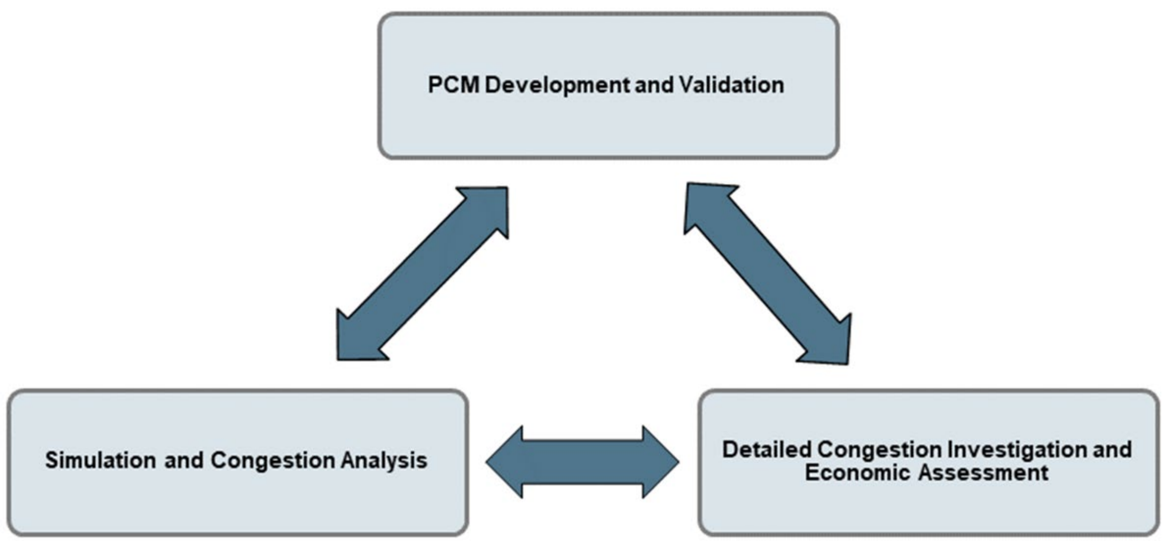
In considering how to assess the value to ratepayers of proposals to reduce gas-fired generation local capacity requirements in areas, the ISO recognizes that additional coordination on the long-term need for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes. If there are sufficient gas-fired generation resources to meet local capacity needs over the planning horizon, there are no needs for reliability-driven reinforcement; rather, the question shifts to the economic value provided by the reduction in local capacity requirement for the gas-fired generation. However, the gas-fired generation may still be required for system or flexible capacity reasons. As noted in Chapter 1, existing legislation[73] calls for the CPUC to provide to the ISO by March 31, 2024, resource projections that are expected to reduce by 2035 the need to rely on non-preferred resources in local capacity areas, however these projections are not yet reflected in the portfolios provided by the CPUC for the 2022-2023 Plan.

[73] SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

4.4 Study Steps of Production Cost Simulation in Economic Planning

As discussed earlier, production benefits are assessed through production cost simulation. The study steps and the timelines of production cost simulation in economic planning are later than the other transmission planning studies within the same planning cycle. This is because the production cost simulation needs to consider upgrades identified in the reliability and policy assessments, and the production cost-model development needs to be coordinate with the entire WECC and the management of a large volume of data. In general, production cost simulation in economic planning has three components, which interact with each other: production cost simulation database development and validation, simulation and congestion analysis, and production benefit assessments of congestion mitigation. Each of these steps is described in more detail in Appendix G. Because of the complexity of the models and analysis, there is often iteration between the three steps as a careful review of results lead to revisiting model aspects. Figure 4.4-1 shows these components and their interaction.

Figure 4.4-1: Steps of Production Cost Simulation in Economic Planning



The final product of this analysis is an assessment of the volume and cost impact of congestion on the transmission system, as well as of the effectiveness of different mitigations across all hours of the study year. These results must then be combined with other economic benefits derived through power flow analysis.

4.5 Production cost simulation tools and database

The ISO primarily used the Hitachi GridView™ software version 10.3.45 for this economic planning study.

The ISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The ISO may also develop an optional 5-year case for providing a data point in validating the benefit calculation of transmission upgrades by assessing a five-year period of benefits before the 10-year case becomes relevant.

The major assumptions of system modeling used in the GridView PCM development for the economic planning study are set out in Appendix G.

The 2022-2023 transmission planning process PCM development started from the ADS PCM 2032 version 2.0, which was released by WECC on August 22, 2022. The ISO then modified the network model for the ISO system to exactly match the policy assessment power flow cases for the entire ISO planning area. The transmission topology, transmission line and transformer ratings, generator location, and load distribution are identical between the PCM and policy assessment power flow cases. Appendix G also highlights the major ISO enhancements and modifications to the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) database that were incorporated into the ISO's database. It is noted that details of the modeling assumptions and the model itself are not itemized for the rest of the Western Interconnection in this document, but the final PCM is posted on the ISO's market participant portal once the study is final.

As a norm for economic planning studies, the production cost simulation models 1-in-2 weather conditions load in the system to represent typical or average load conditions across the ISO system. The base portfolio PCM used the CEC California Energy Demand Updated Forecast for 2032 with high electrification load, consistent with the demand forecast in the reliability assessment as described in Chapter 2. Different from previous planning cycles, the sensitivity portfolio PCM in this planning cycle used different load forecast from the base portfolio PCM, which is the 2035 energy demand updated forecast with high electrification load. Generator locations and installed capacities in the PCM are consistent with the policy assessment power flow case for 2032, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

The CPUC IRP base and sensitivity portfolios included out-of-state wind resources in different areas. Some of the out-of-state wind resources in the CPUC IRP portfolios expected to require new transmission, while some rely on existing transmission, to deliver their wind energy to the ISO load. For the out-of-state wind resources that require new transmission, the CPUC IRP portfolio provided specified injection points to the ISO system, but did not specify particular out-of-state transmission projects to deliver the resources to the ISO boundary.

In the planning PCM in this planning cycle, New Mexico wind generation that requires new transmission was modeled at the Pinal Central 500 kV bus in Arizona, which is consistent with the last planning cycle. This is equivalent to assuming that a new transmission line would be built to deliver New Mexico wind generation to the Pinal Central 500 kV bus.

The CPUC IRP base portfolio included out-of-state wind with 1,062 MW of capacity identified in two alternative locations, Wyoming or Idaho areas, which are expected to require new transmission. In the planning PCM in this planning cycle, Wyoming wind was modeled associated with the TransWest Express project as baseline assumption in the base portfolio

PCM. The Idaho wind scenario was also assessed in the SWIP North project assessment as set out in Section 3.6.

The 2022-2023 planning PCM continued to use the multi-block renewable generator model that was first developed and used in the 2019~2020 planning cycle PCM. This model was applied to all ISO wind and solar generators. Each generator was modeled as five equal and separate generators (blocks) with identical hourly profiles, and each block's Pmax was 20% of the Pmax of the actual generator. Each block had a different curtailment price around $-25/MWh

The ISO continued its modeling of battery storage, refined through the course of the 2019-2020 planning cycle, to reflect limitations associated with the depth of discharge of battery usage cycles (DoD or cycle depth) and replacement costs associated with the cycle life (i.e. the number of cycles) and depth of discharge the battery is subjected to. In this refined battery model, the battery's operation cost was modeled as a flat average cost.

4.6 Base Portfolio Production Cost Simulation Results

This section shows the summary of base portfolio production cost simulation results. The detailed results are included in Appendix G.

4.6.1 Summary of congestion results

High-level assessments were conducted in this section on the constraints that may have a large impact on the bulk system or the heavily congested areas, or showed recurring congestion. The assessment results are shown in Table 4.6-1.

Table 4.6-1: Summary of high-level investigation on major transmission congestions

Constrained area or branch group	Cost (M$)	Duration (Hours)	Overview of investigation
SCE NOL	80.06	6,214	SCE North of Lugo area congestion was observed mostly on the Kramer-Victor 230 kV lines under normal condition and on the Lugo 500/230 kV transformer under N-1 contingency of the Lugo 500/230 kV transformer. Renewable resources in this area, especially in the Kramer area, identified in the CPUC base portfolio, are the driver of the congestion in the SCE NOL area.
COI Corridor	52.83	1,151	COI congestion increased compared with the results in the previous planning cycle. This was mainly caused by the increase of renewable resources in the Northwest regions in the ADS PCM case, especially in the south Oregon area.
Path 26 Corridor	47.32	1,896	Path 26 corridor congestion was mostly attributed to the Path 26 path rating binding and the Whirlwind- Midway 500 kV line normal rating binding. The congestion was mostly observed when the Path 26 flow was from south to north. The main driver of the Path 26 corridor congestion is the large amount of renewable generation in Southern CA identified in the CPUC portfolio
GridLiance/VEA	40.37	3,547	The Innovation-Desert 230 kV line was the most congested line in the GridLiance West/VEA area. The relatively low line ratings of the Innovation-Desert 230 kV lines are the main driver of the congestion.
PG&E Panoche/Oro Loma area	32.24	2,213	Congestions on 115 kV and 70 kV lines in the PG&E's Panoche/Oro Loma area were observed under both normal and contingency conditions. Local solar generations and loop flow between the 230 kV system and 115/70 kV system contributed most to the congestion in this area. Congestion was also observed in real system operation in the Panoche/Oro Loma area.
SDGE San Diego Southern	13.91	1,018	Congestion in the San Diego area was observed mainly on the Suncrest-Sycamore 230 kV line and Silvergate-Bay Boulevard 230 kV line. The congestion was attributed to the solar generation in the Imperial area and the import from Arizona through the SWPL and Sunrise 500 kV lines. Reliability and policy upgrades from the Imperial Valley area to the SCE system that were proposed in this planning cycle will help to mitigate the San Diego congestion.
PG&E Fresno	13.81	1,012	PG&E's Fresno area congestion were observed mainly in the Henrietta 115 kV system, specifically the congestion on GWF_HP – Contadina – Jackson under P7 contingency of losing

Constrained area or branch group	Cost (M$)	Duration (Hours)	Overview of investigation
			the HELM-MCCALL and HENTAP2-MUSTANGSS #1 230 kV lines. Solar generation in the Mustang area and loop flow between the 230 kV and 115 kV systems contributed to the congestion.
SCE W.LA	12.92	197	Congestions were observed in the SCE's Western LA Basin area, mainly on the La Cienega – La Fresa 230 kV line. Potential mitigations were studied in previous planning cycles as part of the LCR reduction study. These congestions will be monitored and investigated in future planning cycles with further clarity of gas-fired generator retirement and battery development at the local areas.
Path 46 WOR	7.86	210	Path 46 congestion was observed mainly as the path rating was derated under scheduled outages on some transmission lines of the path. Reliability and policy upgrades from the Imperial Valley area to the SCE system that were proposed in this planning cycle will help to mitigate the Path 46 congestion.
PG&E Moss Landing-Las Aguilas 230 kV	7.64	334	Congestion on the Moss Landing - Las Aguilas 230 kV line under the N-1 contingency of the Moss Landing - Los Banos 500 kV line occurred when the flow was from Las Aguilas to Moss Landing. The congestion was observed in daytime and in the months when the summer line rating was applied. The congestion is attributed to both the PG&E's Fresno area solar generation and the PG&E's Greater Bay Area load. The series reactor, which was approved in the 2021-2022 cycle, can effectively reduce the flow on the Moss Landing – Las Aguilas 230 kV line. The congestion was aggravated as solar generation in the PG&E Fresno area increased.
Path 15 Corridor	7.49	253	Path 15 corridor congestion was attributed to both Path 15 path rating binding and binding of the 500 kV or 230 kV lines of the path when the flow is from south to north. The Path 15 corridor congestion was highly correlated with the Path 26 congestion, which was also observed when the flow is from south to north.
SDGE/CFE	6.25	1,528	Congestion between the SDGE and CFE systems was observed mainly on Path 45 path rating binding. In spring, congestion on this corridor mainly occurred when there was solar surplus in the CAISO system and the Path 45 flow was from SDGE to CFE. In other times of the year, congestion can be observed when the flow was from CFE to SDGE, which is mainly due to the natural gas price difference across the border. Other factors that impacted the congestion include future renewable generation development in the Imperial Valley area and its representation in the renewable portfolio, and the CFE's generation and load modeling assumption. Further clarity of such factors will be required before detailed investigations need to be conducted.
SCE EOL	5.56	197	The congestion in the SCE East of Lugo area was observed mainly on the Eldorado-McCullough 500 kV line and the Victorville-Lugo 500 kV line under N-1 contingency of the Eldorado-Lugo 500 kV line. Renewable generation in the CPUC portfolio delivered to the Eldorado buses, including the renewable generation in the Eldorado/Mohave area and the GLW/VEA area, and the out-of-state wind in Wyoming and/or Idaho.
SCE Antelope 66kV	5.43	1,265	Neenach-Baily 66 kV line congestion was observed in this planning cycle, which was identified in previous planning cycle as well. This congestion was driven by local renewable generators in the CPUC renewable portfolio, and by the loop flow between the 230 kV and 66 kV system in the Antelope area. Congestion in the Antelope 66 kV area was subject to change with further clarity of the interconnection plans of the future resources.
PG&E Collinsville-Pittsburg 230 kV	4.29	532	Collinsville-Pittsburg 230 kV line congestion was correlated with COI congestion, and can also be impacted by future offshore wind development.
PG&E North Valley	3.86	198	PG&E North Valley area congestion (mainly the Round Mountain-Cottonwood 230 kV congestion) was correlated with COI congestion, and can also be impacted by future offshore wind development.
PDCI	1.50	157	PDCI congestion was observed when the flow was in either direction. The congestion in north to south direction was correlated with the COI congestion, and the congestion in south to north direction was correlated with the Path 26 congestion.

4.6.2 Wind and solar curtailment results

Table 4.6-2 shows wind and solar generation curtailment in the ISO system in the base portfolio PCM. In this table, the renewable resources were aggregated by zone based on the transmission constraints to which the resources in the same zone normally contributed in the same direction, or based on geographic locations if there were no obvious transmission constraints nearby.

Table 4.6-2: Wind and solar curtailment summary in the base portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Tehachapi	31,060	743	31,804	2.34%
PG&E Fresno/Kern	17,924	418	18,342	2.28%
SCE Eastern	15,326	618	15,944	3.88%
SDGE IV	8,296	0	8,296	0.00%
SCE NOL	7,403	403	7,805	5.16%
PG&E Diablo OSW	7,635	98	7,734	1.27%
GridLiance/VEA	7,284	170	7,454	2.28%
NM	6,281	230	6,511	3.53%
AZ	5,621	166	5,786	2.86%
SCE EOL	5,465	125	5,590	2.23%
PG&E Central Valley	5,448	15	5,463	0.27%
WY	3,890	147	4,037	3.64%
PG&E Central Coast	2,797	53	2,849	1.85%
SCE Vestal-Rector	2,349	65	2,414	2.69%
PG&E North Valley	2,240	3	2,242	0.13%
NW	1,876	183	2,059	8.90%
SCE Ventura	1,288	51	1,340	3.83%
SCE Antelope 66 kV	926	23	949	2.39%
PG&E Humboldt OSW	618	2	620	0.30%
SCE LA Basin	315	5	320	1.46%
IID	308	0	309	0.05%
SDGE San Diego	262	0	262	0.01%
PG&E GBA	110	1	110	0.71%
Total	**134,719**	**3,518**	**138,237**	**2.54%**

Wind and solar curtailment was reduced compared with the results in the previous cycle although total renewable capacity increased. Curtailment was reduced in some areas notably, specifically in the GridLiance/VEA area, the PG&E Fresno area, and the SCE Tehachapi area. This change was mainly attributed to the following factors:

- Battery capacity increased in the CPUC portfolio. Renewable surplus due to either transmission or system constraints can be used to charge battery instead of being curtailed;
- Transmission upgrades approved in the previous cycle helped to reduce renewable curtailment effectively, specifically GridLiance/VEA 230 kV upgrades in the GridLiance/VEA area, Manning, Collinsville, and Moss Landing-Las Aguilas upgrades in the PG&E area; and

- Improved busbar mapping for battery and renewable generators further helped to reduce renewable curtailment, especially in the SCE Tehachapi area.

4.7 Economic Planning Study Requests

4.7.1 Overview of economic planning study requests

As part of the economic planning study process, economic planning study requests are accepted by the ISO to be considered in addition to the congestion areas identified by the ISO. These study requests are individually considered for designation as a High Priority Economic Planning Study for consideration in the development of the transmission plan. These economic study requests are distinct from the interregional transmission projects discussed in Chapter 5, but the interregional transmission projects discussed in Chapter 5 may be considered as options to meeting the needs identified though the economic planning studies.

Other economic study needs driven by stakeholder input have also been identified through other aspects of the planning process as well. Those are also set out here, with the rationale for proceeding to detailed analysis where warranted.

The ISO's tariff and Business Practice Manual allows the ISO to select from economic study requests and other sources the high priority areas that will receive detailed study while developing the Study Plan, based on the previous year's congestion analysis. Recognizing that changing circumstances may lead to more favorable results in the current year's study cycle, the ISO has over the past number of planning cycles carried all study requests forward as potential high-priority study requests, until the current year's congestion analysis is also available for consideration in finalizing the high-priority areas that will receive detailed study. This additional review gives more opportunity for the study requests to be considered, that can take into account on a case-by-case basis the latest and most relevant information available.

Accordingly, the ISO reviewed each regional study or project being considered for detailed analysis, and the basis for carrying the project forward for detailed analysis as high-priority economic planning studies – or not – is set out in this section. The section also describes how the study requests or projects selected for detailed analysis were studied, e.g. on a stand-alone basis or as one of several options of a broader area study.

4.7.2 Summary of economic planning study request evaluation

The received study requests and the evaluation results for the requests are summarized in Table 4.7-1. Detailed evaluations for the study requests for purposes of selecting the final list of high-priority economic planning studies are included in Appendix G.

Table 4.7-1: Economic study requests

No.	Study Request	Submitted By	Location	Evaluation Results
1	SWIP North Project	LS Power	ID/NV	Selected to receive detailed assessment as a transmission alternative to interconnect Idaho wind generators as proposed in the CPUC portfolio. Also, it can be an alternative to mitigate COI corridor congestion.
2	NGIV2 Project	NGIV2 and IID	AZ/CA	Identified as a component of policy upgrade in southern California.
3	Fresno Avenal Area Congestion	PG&E	PG&E Fresno Avenal area	No significant congestion was observed in this area. No further assessment in this planning cycle
4	Inyokern 230 kV Upgrade	SCE	North of Lugo area	No significant congestion was observed in this area. No further assessment in this planning cycle
5	PTE Project	California Western Grid Development	Northern/Southern CA	Selected to receive detailed assessment as a transmission alternative to mitigate Path 26 corridor congestion
6	Moss Landing – Las Aguilas 230 kV line reconductoring	Vistra	Northern CA	The interim solution of adding 10 ohm series reactor on the Moss Landing – Las Aguilas 230 kV line that was approved in the 2021-2022 TPP cycle can effectively reduce flow on the line. However, congestion on this line under the Moss Landing-Los Banos 500 kV line N-1 contingency was still observed in the Base Portfolio PCM study because the PG&E Fresno area solar generation increases or the Great Bay Area load increased compared with the solar generation and load in the last planning cycle. The congestion was aggravated in the Sensitivity Portfolio PCM. Long term solution will be needed, but further clarify of load and resource assumptions in the PG&E Fresno and Greater Bay areas is required in order to conduct comprehensive assessment. This congestion will be monitored and reassessed in future planning cycle.
7	GLW 500 kV Upgrade Project	GridLiance West	Southern NV	Policy need was identified in this planning cycle. Significant congestion was observed in the GLW/VEA area. This study request was selected to receive detailed production cost simulation to evaluate the effectiveness of mitigating congestion. Economic assessment was also conducted.
8	GLW Geothermal Upgrade	GridLiance West	Southern NV	Policy upgrade was identified in this area, which is an alternative to this study request. No detailed production cost simulation and economic assessment were conducted in this planning cycle.

4.8 Detailed Investigation of Congestion and Economic Benefit Assessment

The ISO selected the high priority study areas listed in Table 4.8-1 for further detailed assessment. This was done after evaluating identified congestion, considering potential local capacity reduction opportunities and stakeholder-proposed reliability projects citing material economic benefits, and reviewing stakeholders' study requests, consistent with tariff Section 24.3.4.2. The ISO then conducts its technical and economic evaluations, to select the most effective and efficient recommendation. Details of the economic and technical comparisons of alternatives are provided in Appendix G.

High priority areas were selected not solely based on congestion costs or duration, but by taking other considerations into account. Facilities identified as potential mitigations in those study areas include stakeholder proposals from a number of sources: request window submissions that cite economic benefits, economic study requests and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements.

Congestion on radial transmission lines or some local areas may not be selected as a high priority study even though the congestion cost or duration are relatively large and if the congestion was only driven by local renewable generators identified in the CPUC default renewable portfolio. Congestion in these areas is subject to change with further clarity of the interconnection plans or busbar mapping of future resources.

The stakeholder-proposed mitigations being carried forward for detailed analysis are set out in Table 4.8-1 for ease of tracking where and how these stakeholder proposals were addressed.

The detailed analysis also considers other ISO-identified potential mitigations which have been listed in Table 4.8-1 as well. The detailed study results can be found in Appendix G.

Table 4.8-1: Areas receiving detailed economic benefit investigation

Detailed investigation	Alternative	Proposed by	Reason
Path 26 corridor congestion	Midway-Windhub 500 kV line	ISO	Recurring congestion with large congestion cost. The mitigation alternatives are expected to help to mitigate the congestion
	PTE project	Western Grid	
GLW/VEA area congestion	GLW 500 kV Upgrade	GridLiance West	Congestion with a large congestion cost, although the GLW 230 kV upgrades approved in the last TPP cycle were modeled. The mitigation alternatives are expected to help to mitigate the congestion and reduce renewable curtailment in the GridLiance West/VEA area. Policy need was identified.
PG&E Panoche/Oro Loma area congestion	Multiple alternatives, including SPS, re-rating or reconductoring, and operation summer setup, and the combinations of alternatives	ISO	Significant congestions on the 70 kV and 115 kV in this area were identified in this planning cycle. Some identified congestions are consistent with existing congestion in actual system operation. Detailed analysis on the production cost simulation results can help to understand the issues. The alternatives potentially can help to mitigate the congestion
PG&E Fresno Henrietta 115 kV congestion	Multiple alternatives, including new 115 kV transmission lines and SPS	ISO	Congestion with high congestion cost. It is a critical constraint in the Fresno area that impacts future renewable development in this area. It also indicated potential 230 kV and 115 kV loop flow issue under contingency condition in this area. Potentially mitigate or reduce the identified congestion
Idaho wind scenario with SWIP North	SWIP North	LS Power	Idaho wind scenario with new transmission upgrade was suggested in CPUC portfolio. SWIP North was studied as a potential transmission upgrade alternative for Idaho wind, also it can potentially help to mitigate COI congestion
SCE North of Lugo congestion	Kramer to Victor and Victor to Lugo 230 kV upgrades, including Lugo 500/230 kV transformer	ISO	Significant congestion was observed in the SCE North of Lugo area, especially on the Kramer to Victor 230 kV lines and the Lugo 500/230 kV transformers. Policy need was identified.
	Kramer to Lugo 500 kV upgrade		

This study step consists of conducting detailed investigations and modeling enhancements as needed. To the extent that economic assessments for potential transmission solutions are necessary, the production benefits and other benefits of potential transmission solutions are based on the ISO's Transmission Economic Analysis Methodology (TEAM),[74] and potential economic benefits are quantified as reductions of ratepayer costs.

In addition to the production benefit, other benefits were also evaluated as needed. As discussed in Section 4.2, other benefits are also taken into account on a case-by-case basis, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven.

All costs and payments provided in this section are in 2022 real dollars.

Finally, it is important to reiterate that all regional transmission solutions – other than modifications to existing facilities, are subject to the ISO's competitive solicitation process as set out in the ISO's tariff. While many projects have been submitted with narrowly defined project scopes, the ISO is not constrained to only study those scopes without modification, or to study the projects exclusively on the basis under which the proponent suggested.

4.9 Summary and Recommendations

The ISO conducted production cost modeling simulations in this economic planning study. Grid congestion was identified and evaluated; the congestion studies helped guide the specific study areas that were considered for further detailed analysis. Other factors, including the ISO's commitment to consider potential options for reducing the requirements for local gas-fired generation capacity and prior commitments to continue analysis from previous years' studies, also guided the selection of study areas.

The ISO then conducted extensive assessments of potential economic transmission solutions. These potential transmission solutions included stakeholder proposals received from a number of sources including: request window submissions that cited economic benefits, economic study requests, and comments in various stakeholder sessions. Alternatives also included interregional transmission projects as set out in Chapter 5 of the 2022-2023 Transmission Plan.

The study results in this planning cycle were heavily influenced by certain ISO planning assumptions driven by overall industry conditions. In particular, the longer-term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined, in the CPUC's integrated resource planning process, but actionable direction regarding the need for these resources for those purposes is not yet available. As noted earlier existing legislation[75] calls for the CPUC to provide to the ISO by March 31, 2024, resource projections that are expected to reduce by 2035 the need to rely on non-preferred resources in local capacity areas, however these projections are not yet reflected in the portfolios provided by the CPUC for the 2022-2023 Plan. As there were no material change in the assumption around the value of

[74] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

[75] SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

reducing capacity requirements in this planning cycle, the ISO did not update the results of the local capacity reduction assessment; rather, the capacity value results of previous planning cycle were used in the economic assessment for the transmission projects that potentially had benefit of reducing local capacity. The ISO recognizes that the capacity value of many of these projects will need to be revised when actionable direction on the need for gas-fired generation for system and flexible needs is available.

Out-of-state wind and transmission upgrades were assessed in this planning cycle using both the Base portfolio, specifically, the scenario with Idaho wind and SWIP North project was studied as an alternative to the scenario of Wyoming wind and TransWest Express project.

The overall economic planning study results in the 2022-2023 planning cycle are summarized in Table 4.9-1, including the Base portfolio out-of-state wind study results.

Table 4.9-1: Summary of economic assessment in the 2022-2023 planning cycle

Congestion or study area	Alternative	Economic Assessment Result	Economic Justification	Other Justification
Path 26 corridor congestion	Midway-Windhub 500 kV line	Path 26 corridor congestion was partially mitigated; Ratepayer benefit is not sufficient.	No	No
	PTE project	Path 26 corridor congestion was partially mitigated; Ratepayer benefit is not sufficient.	No	No
GLW/VEA area congestion	GLW 500 kV Upgrade	GLW/VEA congestion was partially mitigated; Ratepayer benefit is not sufficient.	No	Policy need was identified
PG&E Panoche/Oro Loma area congestion	Modify the 70 kV summer setup	70 kV congestion was mitigated, but 115 kV congestion was aggravated; Ratepayer benefits is not sufficient.	No	No
	SPS of tripping local solar generators under the Panoche-Mendota 115 kV line N-1 contingency	Not effective to mitigate either 70 kV or 115 kV congestion.		
	Rerating the 115 kV lines	115 kV congestion was mitigated, but 70 kV congestion was not mitigated; Ratepayer benefit is not sufficient.		
	Modify the 70 kV summer setup plus rerating the 115 kV lines	Most of 70 kV and 115 kV congestion was mitigated; Ratepayer benefit is not sufficient.		
	Modify the 70 kV summer setup plus rerating the 115 kV lines plus SPS of tripping local solar generators	Most of 70 kV and 115 kV congestion was mitigated; Ratepayer benefit is not sufficient.		
PG&E Fresno Henrietta 115 kV congestion	CWF – Contadina – Jackson 115 kV double circuit	Congestion was mitigated; Ratepayer benefits not sufficient.	No	No
	SPS of opening the GWF-Contadina 115 kV line under the Helm-Mc Call and Henrietta Tap2 – Mustang 230 kV lines N-2 contingency	Congestion was mitigated; Recommended PG&E to further evaluate feasibility and reliability implication of implementing the RAS.		
Idaho wind scenario with SWIP North	SWIP North	COI congestion was partially mitigated; Ratepayer benefits not sufficient.	No	No
SCE North of Lugo congestion	Kramer to Lugo 230 kV upgrade	Kramer-Lugo corridor congestion was mitigated; Ratepayer benefits not sufficient.		Policy need was identified
	Kramer to Lugo 500 kV upgrade			

In summary, no transmission solutions were found to have sufficient economic benefits to proceed solely on the merits of the economic study results. Therefore, the CAISO will not recommend any economic-driven transmission upgrades in this planning cycle.

Transmission alternatives assessed in this chapter can help to address transmission congestion or renewable curtailment issues in respective study areas. Based on the results of the economic assessment and the production cost simulation, the ISO will coordinate with PG&E to further investigate summer setup and other feasible operation and transmission solution to mitigate the Panoche/Oro Loma area congestion and renewable curtailment issue. The ISO will also coordinate with PG&E to investigate the feasibility of the SPS solution or other potential transmission solution to mitigate Henrietta 115 kV congestion.

The ISO performed additional economic studies of the SWIP North project. The detailed studies conducted in the 2020-2021 Transmission Plan demonstrated that – without clear policy support for accessing Idaho resources for resource planning purposes – the project on its own provided significant economic benefits, but not sufficient to warrant the cost of the project to ISO ratepayers. These circumstances are now evolving, as there is greater support for accessing Idaho wind resources based on the renewable generation portfolios provided by the CPUC for this year's studies, as well as the portfolios that have already been provided for the 2023-2024 transmission plan. The ISO did conduct an additional study of the SWIP North project by comparing production cost results with and without the SWIP North project, and with incremental Idaho wind resources modeled in both cases. The analysis provides useful complementary insights. Please refer to Chapter 3.

Two policy transmission upgrades identified in Chapter 3 were assessed in this chapter to compare economic benefits of different transmission alternatives. They are the GLW 500 kV Upgrade and the SCE North of Lugo area Kramer to Lugo Upgrade. All proposed transmission alternatives showed economic benefit greater than zero to the CAISO ratepayers, which provide additional justification for these transmission upgrades.

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Chapter 5

5 Interregional Transmission Coordination

The ISO conducts its coordination with neighboring planning regions through the biennial interregional transmission coordination framework established in compliance with FERC Order No. 1000. The ISO's 2022-2023 transmission planning cycle was completed during the even-year portion of the 2022-2023 interregional transmission coordination cycle.

The ISO opened its 2022-2023 ITP submission window in the first quarter of 2022, during which proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2022-2023 transmission planning process. During the submission period, seven projects were submitted by project sponsors. However, as part of the submission validation process, it was determined that only one project met the requirement of an interregional transmission project. The project only connects the ISO and WestConnect. With WestConnect not finding a regional need for this project, it will not be considered an Order 1000 interregional transmission project and no interregional projects will be moving into year two.

5.1 Interregional Transmission Coordination per FERC Order No. 1000

The ISO's interregional coordination and interregional transmission project study process was developed to align with FERC Order No. 1000 requirements. The FERC Order No. 1000 broadly reformed the regional and interregional planning processes of public utility transmission providers, and as part of that reform, also required improved coordination across neighboring regional transmission planning processes through procedures for joint evaluation and sharing of information among established transmission planning regions. For the ISO, these coordination processes are in place with our neighboring planning entities, WestConnect and Northern Grid, and they and the ISO are referred to collectively as the Western Planning Regions (WPRs). While FERC Order No. 1000 only requires comment tariff provisions between pairs of neighboring planning entities, enabling for example the ISO to have different coordination provisions with WestConnect than with Northern Grid, the ISO is fortunate that a common set of coordination provisions have been established across all three. This greatly simplifies the coordination process.

In addition to tariff provisions establishing the coordination process, the WPRs developed certain business practices for the specific purpose of providing stakeholders visibility and clarity on how the WPRs would engage in interregional coordination activities among their respective regional planning processes. Commensurate with each WPR's regional arrangement with its members, these business practices were incorporated into the WPR regional processes to be followed within the development of regional plans. For the ISO, these business practices have been incorporated into the ISO's Business Practice Manual (BPM) for the Transmission Planning Process.

In general, the interregional coordination order requires that each WPR:

(1) Commit to developing a procedure to coordinate and share the results of its planning region's regional transmission plans to provide greater opportunities for the WPRs to identify possible interregional transmission facilities that could address regional transmission needs more efficiently or cost effectively than separate regional transmission facilities;

(2) Develop a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;

(3) Establish a formal agreement to exchange planning data and information among the WPRs, at least annually; and

(4) Develop and maintain a website or e-mail list for the communication of information related to the interregional transmission coordination process.

On balance, the ISO fulfills these requirements by following the processes and guidelines documented in the BPM for the Transmission Planning Process and through its development and implementation of the transmission planning process.

5.1.1 Procedure to Coordinate and Share ISO Planning Results with other WPRs

The ISO exchanges its interregional information with the other WPRs in two ways: an annual coordination meeting hosted by the WPRs, and a process by which ITPs can be submitted to the ISO for consideration in its transmission planning process. While the annual coordination meetings are organized by the WPRs, one WPR is designated as the host for a particular meeting and would be responsible for facilitating the meeting. The annual coordination meetings are generally held in February of each year, but no later than March 31. Hosting responsibilities are shared by the WPRs in a rotational arrangement that has been agreed to by the WPRs. The ISO hosted the 2022 meeting and WestConnect is hosting the 2023 meeting.

In general, the purpose of the coordination meeting is to provide a forum for stakeholders to discuss planning activities in the West, including a review of each region's planning process, its needs and potential interregional solutions, an update on ITP evaluation activities, and other related issues. It is important to note that the ISO's planning processes are annual while the planning processes of NorthernGrid and WestConnect are biennial. To address this difference in planning cycles, the WPRs have agreed to annually share the planning data and information that is available at the time the annual interregional coordination meeting is held, divided into an "even" and "odd"-year framework. Specifically, the information which the ISO shares is shown in Table 5.1-1.

Table 5.1-1: Annual Interregional Coordination Information

Even Year	Odd Year
Most recent draft transmission plan	Most recent draft transmission plan
ITPs that: • Were being considered within the previous odd year draft transmission plan; • Are being considered within the previous odd-year draft transmission plan for approval and/or awaiting “final approval” from the relevant planning regions; and • Have been submitted for consideration in the even-year transmission plan.	ITPs that: • Were being considered within the previous even year draft transmission plan; and • Were considered in the even-year draft transmission plan and approved by the ISO Board for further consideration within the odd-year draft transmission plan.

5.1.2 Submission of Interregional Transmission Projects to the ISO

As part of its transmission planning process, the ISO provides a submission window during which proponents may submit their ITPs into the ISO’s annual planning process within the current interregional coordination cycle. The submission window is open from January 1 through March 31 of every even-numbered year. Interregional Transmission Projects will be considered by the WPRs on the basis identified in Section 5.2.

An ITP submission must include specific technical and cost information for the ISO to consider during its validation/selection process of the ITP. For the ISO to consider a proponent’s project as an ITP, it must have been submitted to and validated by at least one other WPR. Once the validation process has been completed, each WPR is then considered to be a Relevant Planning Region. All Relevant Planning Regions consider the proposed ITP in their regional process. For the ISO, validated ITPs will be included in the ISO’s Transmission Planning Process Unified Planning Assumptions and Study Plan for the current planning cycle and evaluated in that year’s transmission planning process.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

5.1.3 Interregional Transmission Project Submittal Requirements

As described in the ISO’s Business Practice Manual (BPM) for the Transmission Planning Process, ITPs may be submitted into the ISO’s transmission planning process on January 1 through March 31 of every even year of the interregional transmission coordination process. The ITPs must be properly submitted and in doing so must meet the following requirements:

- The ITP must electrically interconnect at least two Order 1000 planning regions;
- While an ITP may connect two Order 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO’s transmission planning process;

- When a sponsor submits an ITP into the regional process of an Order 1000 planning region, it must indicate whether it is seeking cost allocation from that Order 1000 planning region; and
- When a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess an ITP. This applies whether or not cost allocation is requested.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

5.1.4 Evaluation of Interregional Transmission Projects by the ISO

Once the submittal and validation process have been completed, the ISO shares its planning data and information with the other Relevant Planning Regions and develops a coordinated evaluation plan for each ITP to be considered in its regional planning process. The process to evaluate an ITP can take up to two years where an “initial” assessment is completed in the first or even year and, if appropriate, a final assessment is completed in the second or odd year. The assessment of an ITP in a WPR’s regional process continues until a determination is made on whether the ITP will or will not meet a regional need within that Relevant Planning Region. If a WPR determines that an ITP will not meet a regional need within its planning region, no further assessment of the ITP by that WPR is required. Throughout this process, as long as an ITP is being considered by at least two Relevant Planning Regions, it will continue to be assessed as an ITP for cost allocation purposes; otherwise, the ITP will no longer be considered within the context of Order No. 1000 interregional cost allocation. However, if one or more planning regions remain interested in considering the ITP within its regional process even though it is not on the path of cost allocation, it may do so with the expectation that the planning region(s) will continue some level of continued cooperation with other planning regions and with WECC and other WECC processes to ensure all regional impacts are considered.

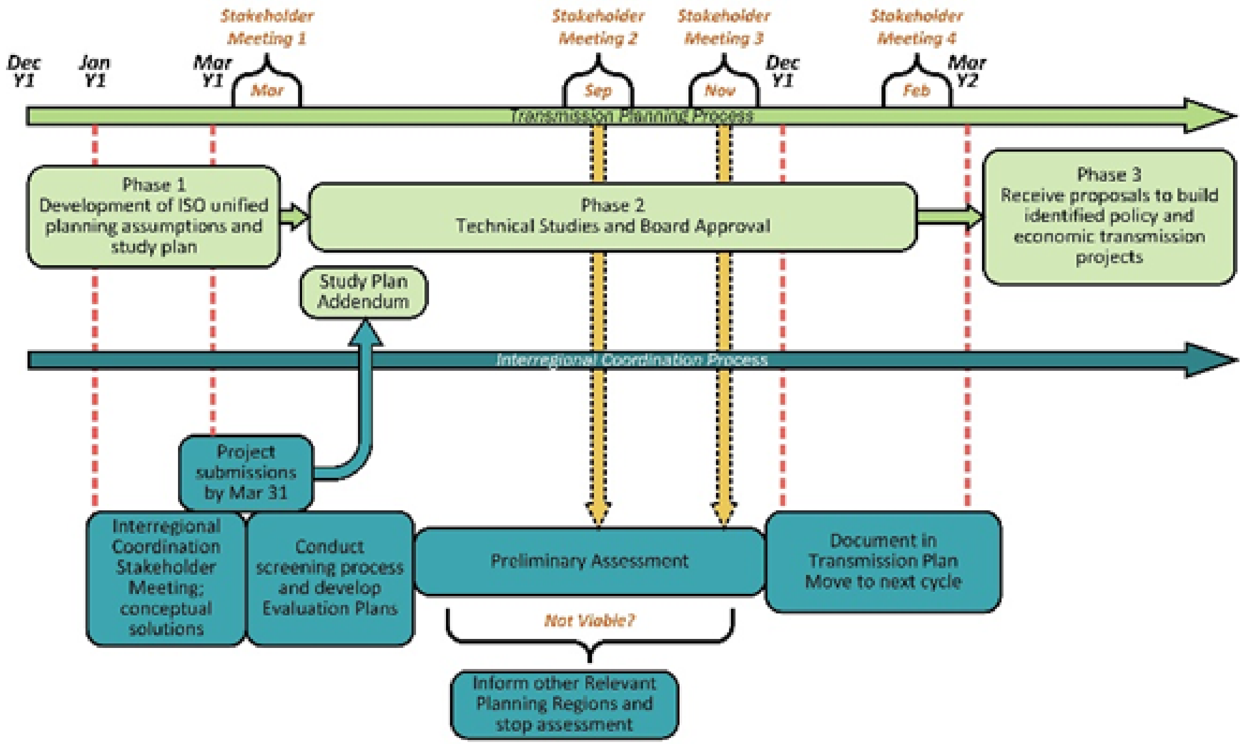
5.1.4.1 Even Year ITP Assessment

The even-year ITP assessment begins when the relevant planning regions initiate the coordinated ITP evaluation process. This evaluation process constitutes the relevant planning regions’ formal process to identify and jointly evaluate transmission facilities that are proposed to be located in planning regions where the ITP was submitted. The goal of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP that will be used by all relevant planning regions in their individual evaluations of the ITPs. The relevant planning regions are required to complete the ITP evaluation process within 75 days after the ITP submission deadline of March 31, during which a lead planning region is selected for each ITP proposal to develop and post for ISO stakeholder review, a coordinated ITP evaluation process plan for each ITP. Once the ITP evaluation plans are final, each relevant planning region independently considers the ITPs that have been submitted into its regional planning process.

As with the other relevant planning regions, the ISO assesses the ITP proposals under the ISO tariff. As illustrated in Figure 5.1-1, the ISO shares this information with stakeholders through its regularly scheduled stakeholder meetings, as applicable.

It is important to note that the ISO manages its assessment of an ITP proposal across the two-year interregional coordination cycle in two steps. During the even year, the ISO makes a preliminary assessment of the ITP and once it completes that task, the ISO must evaluate whether consideration of the ITP should continue into the next ISO planning cycle (odd-year interregional coordination process). That determination can be made based on a number of factors including economic, reliability, public policy considerations, and whether the project continues to be considered by at least one other planning region

Figure 5.1-1: Even Year Interregional Coordination Process

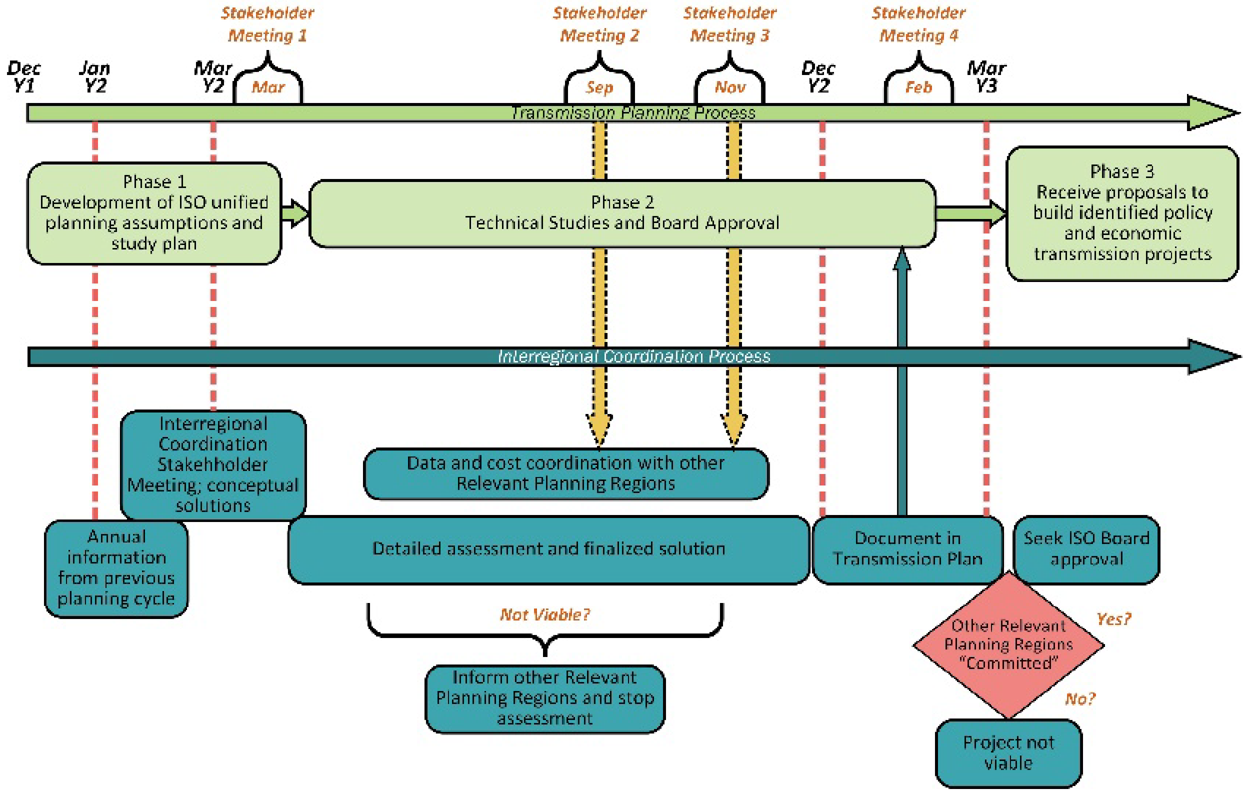


The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation whether the assessment of the ITP should continue in the odd year. The ISO Board's approval of the transmission plan is sufficient to enact its recommendations.

5.1.4.2 Odd-Year ITP Assessment

A recommendation in the even-year transmission plan to continue assessing an ITP will initiate consideration of the ITP in the following, or odd-year transmission planning cycle and will be documented in the odd-year transmission planning process, unified planning assumptions, and study plan. Similar to the even-year coordination process shown in Figure 5.1-1, the ISO will follow the odd-year interregional coordination process shown in Figure 5.1-2.

Figure 5.1-2: Odd Year Interregional Coordination Process



During the odd-year planning cycle, the ISO will conduct a more in-depth analysis of the project proposal, which will include consideration of the timing in which the regional solution is needed and the likelihood that the proposed interregional transmission project will be constructed and operational in the same timeframe as the regional solution(s) it is replacing. The ISO may also determine the regional benefits of the interregional transmission project to the ISO that will be used for purposes of allocating any costs of the ITP to the ISO.

If the ISO determines that the proposed ITP is a more efficient or cost-effective solution to meet an ISO-identified regional need and the ITP can be constructed and operational in the same timeframe as the regional solution, the ISO will then consider the ITP as the preferred solution in the ISO transmission plan. The ISO will document its analysis of the ITP and the other regional transmission solutions.

Once the ISO selects an ITP in the ISO transmission plan, the ISO will coordinate with the other relevant planning regions to determine if the ITP will be selected in their regional plans and whether a project sponsor has committed to pursue or build the project. Based on the information available, the ISO may inform the ISO Board on the status of the ITP proposal and if appropriate, seek approval from the board to continue working with all relevant parties associated with the ITP to determine if the ITP can viably be constructed. Determining viability may take several years during which time the ISO will continue to consider the ITP in its transmission planning process and if appropriate, select it as the preferred solution. The ISO may seek ISO Board approval to build the ITP once the ISO receives a firm commitment to construct the ITP.

5.2 2022-2023 Interregional Transmission Coordination ITP Submissions to the ISO

The ISO opened its 2022-2023 ITP submission window in the first quarter of 2022, when proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2022-2023 transmission planning process. The submission period began on January 1 and closed on March 31. Seven projects and their documentation[76] were submitted by their project sponsors for consideration by the ISO. The submitted projects are shown in Table 5.2-1

Table 5.2-1: ITPs Submitted into the 2020-2021 Submission Period

Project Name	Company	Project Submitted to	Relevant Planning Regions	Cost Allocation Requested From	Description	In Service Date
North Gila – Imperial Valley #2 (NGIV2)	NGIV2, LLC	CAISO, WC	CAISO, WC	CAISO	500 kV line from North Gila to Imperial Valley with 500/230 kV Connection to IID system at new Dunes substation.	2026
SWIP-North	Great Basin Transmission LLC	CAISO, NG	CAISO, NG	CAISO, NG	Midpoint to Robinson Summit 500 kV line.	2025
Del Norte HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Del Norte area in the Pacific Ocean to Pittsburg substation.	2035
Humboldt HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Humboldt area in the Pacific Ocean to Potrero substation.	2030
Cape Mendocino HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Cape Mendocino area in the Pacific Ocean to Moss Landing substation.	2040
Diablo Canyon HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Diablo Canyon call area in the Pacific Ocean to Diablo Canyon substation.	2030
Morro Bay HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Morro Bay call area in the Pacific Ocean to Morro Bay substation.	2030

Following the submission and the screening of the ITP submittals, it was determined that only North Gila – Imperial Valley #2 (NGIV2) project is qualified as an interregional project. More details on the NGIV2 project is provided in Section 5.2.1. Regarding the SWIP-North project, NorthernGrid indicated that since the proposed project is entirely within the NorthernGrid system, it is not qualified as an Order 1000 interregional transmission project. The ISO agreed with the NorthernGrid's assessment and therefore the project was not further studied in the

[76] http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

Order 1000 process. Regarding the five HVDC projects, since the projects were only submitted to the ISO, they are not qualified as an Order 1000 interregional transmission project which requires a project connect at least two western planning regions. The ISO developed its ITP evaluation for the NGIV2 project in coordination with the other relevant planning regions. Given the intent of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP, the NGIV2 evaluation plan satisfy that intent and as such, fulfills Order 1000's requirement of the relevant planning regions to jointly coordinate regional planning processes that evaluate an ITP. In doing so, the NGIV2 evaluation plan documents a common framework, coordinated by the WPRs, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process. The ISO then utilizes this information in its development of all planning data and information that is required for the ISO to assess the ITP in its transmission planning process. Specifically, the information in the evaluation plan is considered an addendum to the approved Transmission Planning Process Unified Planning Assumptions and Study Plan.[77]

5.2.1 North Gila – Imperial Valley Transmission Project and Assessment Results

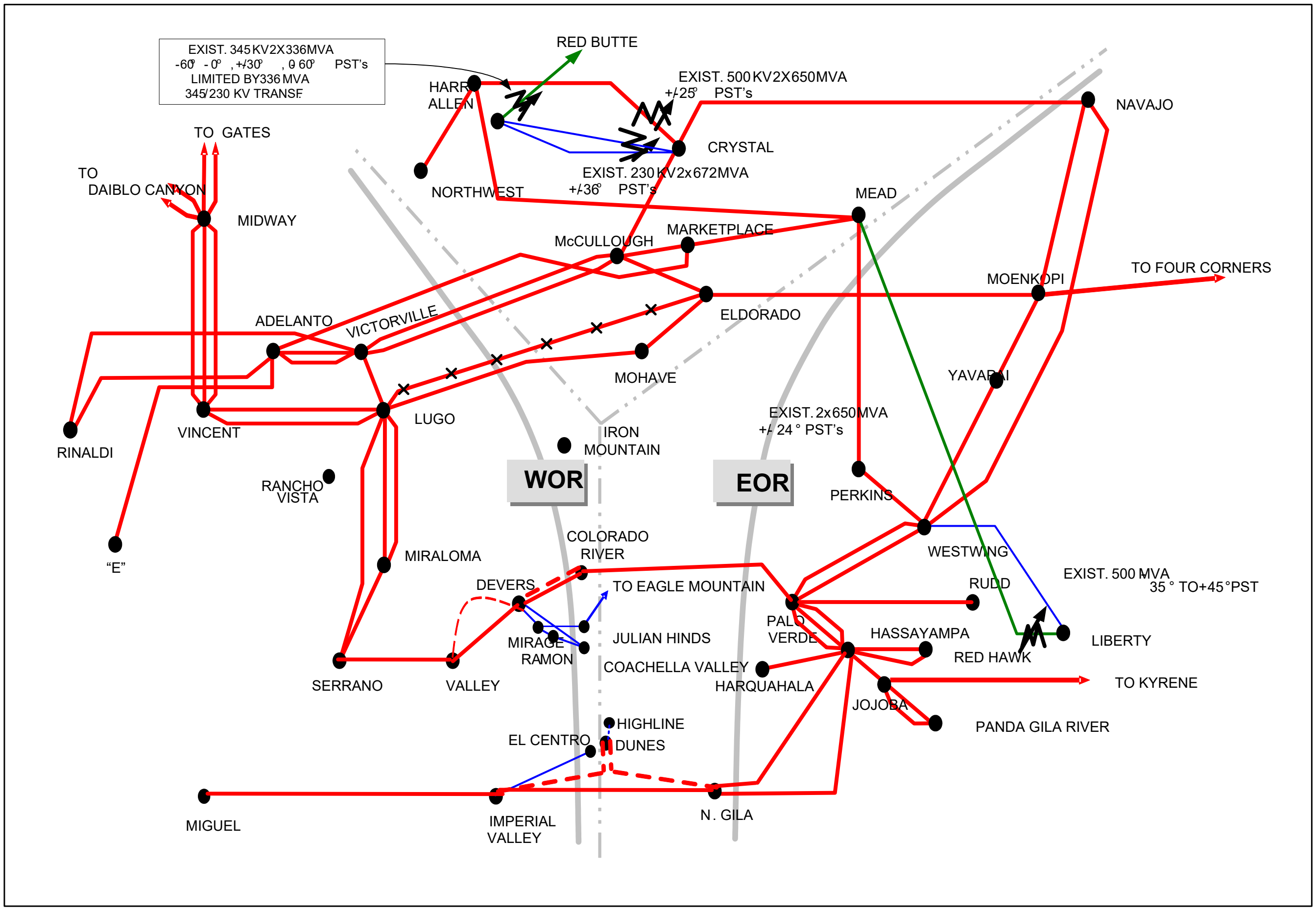
Project Description

The NGIV2, LLC submitted the North Gila-Imperial Valley #2 (NGIV2) Transmission Project for consideration as an Interregional Transmission Project. The NGIV2 is a proposed 500 kV AC transmission project that will extend approximately 90 miles and will be constructed between southwest Arizona and southern California (see Figure 5.2-1). The line will parallel the existing North Gila-Imperial Valley line, also known as the Southwest Power Link (SWPL), and will connect the existing 500 kV North Gila substation (in the WestConnect planning region) with the existing 500 kV Imperial Valley substation (in the California ISO planning region). NGIV2 would be constructed to loop in a new 500/230 kV Dunes substation (in the WestConnect planning region) and would also include construction of a new 230 kV line from Dunes into the existing IID Highline 230 kV substation. A new 500/230 kV transformer would be installed in the Dunes substation as part of the NGIV2 project. This project will become an additional component of the West of Colorado River path (Western Electricity Coordination Council (WECC) path 46) and is expected to increase the East of Colorado River path (WECC path 49) transfer capability by 1,250 MW. Series compensation may be added to the project to balance flows on this new circuit and the existing SWPL line.

NGIV2, LLC completed the WECC 3-phase rating process on September 5, 2019. The NGIV2, LLC is currently evaluating potential alternative routes and working with the responsible regulatory agencies to obtain all necessary project approvals. According to NGIV2, LLC, the project is expected to be in-service by December 2026.

[77] http://www.caiso.com/InitiativeDocuments/FinalStudyPlan-2022-2023TransmissionPlanningProcess.pdf

Figure 5.2-1: NGIV2 Transmission Project



Source: http://www.caiso.com/Documents/NorthGila-ImperialValley2-FinalInterregionalTransmissionProjectEvaluationProcessPlan.pdf

Stated Purpose of the Project

The stated purpose of the NGIV2 project is that it would have reliability, local capacity, resource adequacy, economic, and public policy benefits as well as facilitating integration of out of state wind generation projects.

WestConnect Regional Assessment

On January 11, 2023, WestConnect informed the NGIV2 project sponsor that WestConnect did not identify any regional transmission needs in its 2022-2023 Regional Planning cycle and will not be evaluating the project to meet the identified needs in the ITP. Therefore WestConnect will not have a need to evaluate against the NGIV2 project and the NGIV2 project will not be considered an Order 1000 interregional transmission project.

The project only connects the ISO and WestConnect, and with WestConnect not finding a regional need for this project, the ISO concurs with WestConnect that the NGIV2 will not be considered an Order 1000 interregional transmission project.

The ISO has nonetheless conducted regional analysis policy and economic assessments of this project in Chapters 3 and 4, respectively.

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Chapter 6

6 Other Studies and Results

The studies discussed in this chapter focus on other recurring study needs not previously addressed in preceding sections of the transmission plan and are either set out in the ISO tariff or form part of the ongoing collaborative study efforts taken on by the ISO to assist the CPUC with state regulatory needs. The studies have not been addressed elsewhere in the transmission plan. These presently include the reliability requirements for resource adequacy, simultaneous feasibility test studies, a system frequency response assessment, and a flexible capacity deliverability assessment.

6.1 Reliability Requirement for Resource Adequacy

Section 6.1.1 summarizes the technical studies conducted by the ISO to comply with the reliability requirements initiative in the resource adequacy provisions under Section 40 of the ISO tariff. This section also includes additional analysis supporting long-term planning processes, the local capacity technical analysis and the resource adequacy import allocation study. The local capacity technical analysis addressed the minimum local capacity area requirements (LCR) on the ISO grid. The resource adequacy import allocation study established the maximum resource adequacy import capability to be used in 2023. Upgrades that are being recommended for approval in this transmission plan have therefore not been taken into account in these studies.

6.1.1 Local Capacity Requirements

The ISO conducted short and long-term local capacity technical (LCT) analysis studies in 2022. A short-term analysis was conducted for the 2023 system configuration to determine the minimum local capacity requirements for the 2023 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria as required by the ISO tariff Section 40.3. This study was conducted in January through April through a transparent stakeholder process with a final report published on April 28, 2022. For detailed information on the 2023 LCT Study Report please visit:

http://www.caiso.com/InitiativeDocuments/Final2023LocalCapacityTechnicalReport.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2027 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years respectively. The 2027 LCT Study Report was published on April 28, 2022. For detailed information please visit:

http://www.caiso.com/InitiativeDocuments/Final2027Long-TermLocalCapacityTechnicalReport.pdf

The ISO also conducts a 10-year local capacity technical study every second year, as part of the annual transmission planning process. The 10-year LCT studies are intended to synergize with the CPUC long-term procurement plan (LTPP) process and to provide an indication of whether there are any potential deficiencies of local capacity requirements that need to trigger a new LTPP proceeding. Per agreement between state agencies, they are done on an every-other-year cycle.

The most recent 10-year LCR study was initiated in the 2022-2023 transmission planning process. The ISO undertook a comprehensive study of local capacity areas, examining both the load shapes and new battery charging and discharging characteristics underpinning local-capacity requirements.

For detailed information about the 2032 long-term LCT study results, please refer to the stand-alone report in Appendix J of the 2022-2023 transmission planning process.

As shown in the LCT study reports and indicated in the LCT study manual that the ISO prepares each year setting out how that year's LCT studies will be performed, 12 load pockets are located throughout the ISO-controlled grid as shown in Table 6.1-1; however only 10 of them have local capacity area requirements as illustrated in Figure 6.1-1.

Table 6.1-1: List of Local Capacity Areas and the corresponding service territories within the ISO Balancing Authority Area

No	LCR Area	Service Territory
1	Humboldt	PG&E
2	North Coast/North Bay	
3	Sierra	
4	Stockton	
5	Greater Bay Area	
6	Greater Fresno	
7	Kern	
8	Los Angeles Basin	SCE
9	Big Creek/Ventura	
10	Greater San Diego/Imperial Valley	SDG&E
11	Valley Electric	VEA
12	Metropolitan Water District	MWD

Figure 6.1-1: Approximate geographical locations of LCR areas

Each load pocket is unique and varies in its capacity requirements because of different system configurations. For example, the Humboldt area is a small pocket with total capacity requirements of approximately 140 MW. In contrast, the requirements of the Bay Area are approximately 7,500 MW. The short-term and long-term LCR needs from this year's studies are shown in Table 6.1-2.

Table 6.1-2: Local capacity areas and requirements for 2023, 2027 and 2032

LCR Area	**LCR Capacity Need (MW)**		
	2023	**2027**	**2032**
Humboldt	141	147	154
North Coast/North Bay	857	911	911
Sierra	1,150	1,345	1,450
Stockton	579	555	755
Bay Area	7,312	7,540	7,936
Fresno	1,870	2,179	2,750
Kern	439	320	424
Big Creek/Ventura	2,240	1126	1,366
Los Angeles Basin	7,529	6,131	7,388
San Diego/Imperial Valley	3,332	3,369	4,849
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	25,449	23,623	27,983

Notes:
For more information about the LCR criteria, methodology and assumptions, please refer to the ISO LCR manual.[78]
For more information about the 2023 LCT study results, please refer to the report posted on the ISO website.
For more information about the 2027 LCT study results, please refer to the report posted on the ISO website.

[78] "Final Manual 2023 Local Capacity Area Technical Study," January 14, 2022, http://www.caiso.com/InitiativeDocuments/2023LocalCapacityRequirementsFinalStudyManual.pdf .

6.1.2 Resource adequacy import capability

6.1.2.1 Maximum Import Capability for Resource Adequacy and Future Outlook

The ISO has established the maximum resource adequacy (RA) import capability to be used in year 2023 in accordance with the ISO tariff Section 40.4.6.2.1. These data can be found on the ISO website.[79] The entire import allocation process[80] is posted on the ISO website.

The future outlook for all remaining branch groups can be accessed at the following link:

http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2023-2032.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2024 to accommodate renewable resources development in this area that ISO has established in accordance with Reliability Requirements BPM Section 5.1.3.5. The import capability from IID to the ISO is the combined amount from the IID-SCE_ITC and the IID-SDGE_ITC. In order to achieve an increase to 702 MW total MIC from IID, upgrades on the ISO system are currently complete, awaiting the completion of the IID-owned 230 kV S Line.

The ISO confirms that not all import branch groups or sum of branch groups have enough maximum import capability (MIC) to achieve deliverability for all external renewable resources in the base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2032.

Based on the TPP deliverability studies (and most likely GIP deliverability studies) some scheduling points (branch groups) currently do not have enough deliverability available to make the main CPUC portfolio deliverable without transmission reinforcements. Transmission reinforcements are studied and if necessary will be approved through the TPP.

Table 6.1-6.1-3: TPP deliverability study results regarding CPUC main portfolio

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Failed	For potential increase see mitigation for Lugo-Victorville constraint.
2	MEAD_ITC (MEAD 230)	Failed	For potential increase see mitigation for Lugo-Victorville constraint.
3	IID-SCE_ITC (MIR2)	Failed	For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
4	IID-SDGE_ITC (IVLY2)	Failed	For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
5	MCCULLGH_ITC (ELDORADO500)	Failed	For potential increase see mitigation for Lugo-Victorville constraint.
6	PALOVRDE_ITC (PVWEST)	Failed	For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.

[79] “California ISO Maximum RA Import Capability for year 2023,” available on the ISO’s website at http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2023.pdf.

[80] See general the Reliability Requirements page on the ISO website http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

For scheduling points where the CPUC main portfolio has failed the TPP deliverability test, the long-term MIC expansion is not possible without new transmission reinforcements. Please follow the potential mitigations for specific constraints as listed in the table above.

6.1.2.2 Maximum Import Capability Expansion Requests

Per Section 3.2.2.3 of the Transmission Planning Process Business Practice Manual (TPP BPM), requests to perform deliverability studies to expand the maximum import capability have been submitted to the CAISO within 2 weeks after the first stakeholder meeting and not later than the time that the study plan comments were due. The valid maximum import capability expansion requests have identified the intertie(s) (branch group(s)) that require expansion.

The CAISO has evaluated each maximum import capability expansion request to establish if the submitting entity meets the criteria listed in the Tariff Section 24.3.5. The table below includes the valid Maximum Import Capability expansion requests that were submitted for this planning cycle.

Table 6.1-6.1-4: Valid Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource Type
1-4	San Diego Community Power	IID-SCE_ITC (MIR2)	150	Hybrid (Solar/Battery)
		ELDORADO_ITC (WILLOWBEACH)	333	Wind
2-5	Valley Electric Association	MEAD_ITC (MEAD 230)	33	Hydro
			90	Solar
9-10	Sonoma Clean Power	GONDIPPDC_ITC (GONIPP)	68	Geothermal
		MERCHANT_ITC (ELDORADO230)	40	
		IID-SDGE_ITC (IVLY2)	50	
		SILVERPK_ITC (SILVERPEAK55)	13	
11	East Bay Community Energy	SUMMIT_ITC (SUMMIT120)	40	Geothermal
		SILVERPK_ITC (SILVERPEAK55)		
12	Peninsula Clean Energy	IID-SCE_ITC (MIR2)	26	Geothermal
13	Southwestern Power Group II	PALOVRDE_ITC (PVWEST)	1257	Wind

The CAISO has received 12 submissions with requests for MIC expansion. They contained 29 distinct requests (a few were duplicates – the LSE provided the request and the supplier provided a requests for the same resource).

Based on the CAISO interpretation of the Tariff and the Transmission Planning BPM (TP BPM) requirements, 13 distinct requests qualify as valid requests based on the following factors:

1. LSEs with valid RA contracts not already accounted for as Pre-RA Import Commitments or New Use Import Commitment.
2. Submittals by transmission owners – with connection in a neighboring Balancing Authority Area immediately adjacent to the CAISO Controlled Grid.

For the following reasons, 16 distinct requests do not qualify at this time:

1. Submissions by LSEs and/or resource owners with “shortlisted” contracts - since they do not have an existing RA contract with a CAISO LSE.
2. Submissions by resource owners with resources in other Balancing Authority Area (BAA) queue including site exclusivity - since they do not have an existing RA contract with a CAISO LSE.
3. Submissions by owners of Pseudo-ties or Dynamic schedules with Transmission Service Agreements (TSA) to the CAISO border – since they do not have an existing RA contract with a CAISO LSE. The TSA is required to participate in the CAISO energy market as an energy only resource (see Tariff Section 40.8.1.12.1) plus the TSAs are given out on non-simultaneous bases (incompatible with the MIC calculation).

The CAISO has coordinated the valid MIC expansion requests with the policy driven MIC expansion and the total of the two (after elimination of duplicates) was used to identify all branch groups that do not have sufficient Remaining Import Capability to cover both the valid MIC expansion requests and the policy driven MIC expansion.

The exact calculation of the target expanded MIC can be found in Reliability Requirements Business Practice Manual (RR BPM) Section 6.1.3.5, “Deliverability of Imports”.

Table 6.1-6.1-5: Assessment of valid Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Triggers expansion	Comments:
1-4	San Diego Community Power	IID-SCE_ITC (MIR2)	150	No	CPUC portfolio triggers MIC expansion.
		ELDORADO_ITC (WILLOWBEACH)	333	In CPUC portfolio	CPUC portfolio triggers MIC expansion.
2-5	Valley Electric Association	MEAD_ITC (MEAD 230)	33	Potentially	Together with CPUC portfolio triggers MIC expansion.
			90		
9-10	Sonoma Clean Power	GONDIPPDC_ITC (GONIPP)	68	Yes	
		MERCHANT_ITC (ELDORADO230)	40	No	
		IID-SDGE_BG (IVLY2)	50	No or in CPUC portfolio	CPUC portfolio triggers MIC expansion.
		SILVERPK_ITC (SILVERPEAK55)	13	Yes	
11	East Bay Community Energy	SUMMIT_ITC (SUMMIT120)	40	Yes	
		SILVERPK_ITC (SILVERPEAK55)		Yes	
12	Peninsula Clean Energy	IID-SCE_ITC (MIR2)	26	No	CPUC portfolio triggers MIC expansion.
13	Southwestern Power Group II	PALOVRDE_ITC (PVWEST)	1257	No	CPUC portfolio triggers MIC expansion.

If MIC expansion was triggered, the increase in MIC was modeled and tested through deliverability studies: the NQC deliverability study (if applicable in year one), the TPP deliverability study and the GIP deliverability study. One or multiple of these studies can limit the deliverability and therefore the MIC expansion.

NQC deliverability study:

Only 4 scheduling points had a MIC expansion requests that triggered an increase applicable to the 2023 RA year.

Table 6.1-6.1-6: 2023 NQC deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Pass	Temporary expansion included in 2023 MIC.
2	MEAD_ITC (MEAD 230)	Pass	Temporary expansion included in 2023 MIC.
3	IID-SCE_ITC (MIR2)	Failed	Due to delay in "S" line upgrade.
4	IID-SDGE_ITC (IVLY2)	Failed	Due to delay in "S" line upgrade.

The appropriate amount of MWs to the scheduling points that passed the test of the 2023 NQC deliverability study were given to the LSEs as a temporary MIC increase for RA year 2023.

Permanent expansion of MIC depends on the TPP and GIP deliverability study results.

TPP deliverability study:

The TPP deliverability study includes all existing resources with deliverability, new resources with deliverability as dictated by the TPP study plan, all new resources provided in the main policy portfolio provided by the CPUC and the MIC expansion requests submitted to the CAISO.

Table 6.1-6.1-7: TPP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Failed	Included in the CPUC portfolio. For potential increase see mitigation for Lugo-Victorville constraint.
2	MEAD_ITC (MEAD 230)	Failed	Included in the CPUC portfolio. For potential increase see mitigation for Lugo-Victorville constraint.
3	IID-SCE_ITC (MIR2)	Failed	Included in the CPUC portfolio. For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
4	IID-SDGE_ITC (IVLY2)	Failed	Included in the CPUC portfolio. For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
5	GONDIPPDC_ITC (GONIPP)	Failed	For potential increase see mitigation for Lugo-Victorville constraint.
6	SILVERPK_ITC (SILVERPEAK55)	Failed	For potential partial increase see upgrades under SCE North of Lugo area constraints.
7	SUMMIT_ITC (SUMMIT120)	Failed	For potential increase see Drum-Higgins constraint in PG&E Sierra area.

All MIC expansion requests have failed the TPP deliverability test and therefore long-term MIC expansion is not possible without new transmission reinforcements. Please follow the potential mitigations for specific constraints as listed in the table above. Remainder – the MIC expansion requests on their own cannot trigger transmission expansion however some of the MIC expansion requests may end up passing at a later date as long as mitigations move forward for reliability, economic or policy need.

GIP deliverability study:

The GIP deliverability study includes all resources with deliverability included in the TPP deliverability study, (including MIC expansion requests) plus additional resources that have received TPD and DGD allocation prior to this study cycle.

The interrelation between the target expanded MIC and the generation interconnection process can be found in RR BPM Section 6.1.3.6, “Modeling Expended MIC Values in GIP”.

The CAISO has not yet conducted a new cycle of GIP deliverability studies, however, since the GIP deliverability study includes additional new resources with prior TPD and DGD allocation beyond those modeled in the TPP deliverability study, it is reasonably assumed that they would fail the GIP deliverability studies.

Table 6.1-6.1-8: GIP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Failed*	Included in the CPUC portfolio. For potential increase see mitigation for Lugo-Victorville constraint.
2	MEAD_ITC (MEAD 230)	Failed*	Included in the CPUC portfolio. For potential increase see mitigation for Lugo-Victorville constraint.
3	IID-SCE_ITC (MIR2)	Failed*	Included in the CPUC portfolio. For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
4	IID-SDGE_ITC (IVLY2)	Failed*	Included in the CPUC portfolio. For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
5	GONDIPPDC_ITC (GONIPP)	Failed*	For potential increase see mitigation for Lugo-Victorville constraint.
6	SILVERPK_ITC (SILVERPEAK55)	Failed*	For potential partial increase see upgrades under SCE North of Lugo area constraints.
7	SUMMIT_ITC (SUMMIT120)	Failed*	For potential increase see Drum-Higgins constraint in PG&E Sierra area.

* All MIC expansion requests will likely fail the GIP deliverability test and therefore long-term MIC expansion is not possible without new transmission reinforcements. Please follow the potential mitigations for specific constraints as listed in the table above. The mitigations proposed in the TPP must allow the internal resources with prior TPD and DGD allocation to remain deliverable before MIC is allowed to permanently increase to account for import resources included in the CPUC portfolio and if possible to allow for further MIC increase due to MIC expansion requests.

6.2 Long-Term Congestion Revenue Rights Simultaneous Feasibility Test Studies

The Long-term Congestion Revenue Rights (LT CRR) Simultaneous Feasibility Test studies evaluate the feasibility of the fixed LT CRRs previously released through the CRR annual allocation process under seasonal, on-peak and off-peak conditions, consistent with Section 4.2.2 of the Business Practice Manual for Transmission Planning Process and tariff Sections 24.1 and 24.4.6.4

6.2.1 Objective

The primary objective of the LT CRR feasibility study is to ensure that fixed LT CRRs released as part of the annual allocation process remain feasible over their entire 10-year term, even as new and approved transmission infrastructure is added to the ISO-controlled grid.

6.2.2 Data Preparation and Assumptions

The 2022 LT CRR study leveraged the base case network topology used for the annual 2023 CRR allocation and auction process. Regional transmission engineers responsible for long-term grid planning incorporated all the new and ISO-approved transmission projects into the base case and a full alternating current (AC) power flow analysis to validate acceptable system performance. These projects and system additions were then added to the base case network model for CRR applications. The modified base case was then used to perform the market run, CRR simultaneous feasibility test (SFT), to ascertain feasibility of the fixed CRRs. A list of the approved projects can be found in the 2022-2023 Transmission Plan. In the SFT-based market run, all CRR sources and sinks from the released CRR nominations were applied to the full network model (FNM). All applicable constraints that were applied during the running of the original LT CRR market were considered to determine flows as well as to identify the existence of any constraint violations. In the long-term CRR market run setup, the network was limited to 60% of available transmission capacity. The fixed CRR representing the transmission ownership rights and merchant transmission were also set to 60%. All earlier LT CRR market awards were set to 100%, since they were awarded with the system capacity already reduced to 60%. For the study year, the market run was set up for two seasons (with season one being January through March and season three July through September) and two time-of-use periods (reflecting on-peak and off-peak system conditions). The study setup and market run are conducted in the CRR study system. This system provides a reliable and convenient user interface for data setup and results display. It also provides the capability to archive results as saved cases for further review and record-keeping.

The ISO regional transmission engineering group and CRR team must closely collaborate to ensure that all data used were validated and formatted correctly. The following criteria was used to verify that the long-term planning study results maintain the feasibility of the fixed LT CRRs SFT is completed successfully:

- The worst-case base loading in each market run does not exceed 60% of enforced branch rating; and
- There are overall improvements on the flow of the monitored transmission elements.

6.2.3 Study Process, Data and Results Maintenance

A brief outline of the current process is as follows:

- The base case network model data for long-term grid planning is prepared by the regional transmission engineering (RTE) group. The data preparation may involve using one or more of these applications: PTI PSS/E, GE PSLF and MS Excel;
- RTE models new and approved projects and perform the AC power flow analysis to ensure power flow convergence;
- RTE reviews all new and approved projects for the transmission planning cycle;
- Applicable projects are modeled into the base case network model for the CRR allocation and auction in collaboration with the CRR team, consistent with the BPM for Transmission Planning Process Section 4.2.2;
- CRR team sets up and performs market runs in the CRR study system environment in consultation with the RTE group;
- CRR team reviews the results using user interfaces and displays, in close collaboration with the RTE group; and
- The input data and results are archived to a secured location as saved cases.

6.2.4 Conclusions

The SFT studies involved four market runs that reflected two three-month seasonal periods (January through March, and July through September) and two time-of-use (on-peak and off-peak) conditions.

The results indicated that all existing fixed LT CRRs remained feasible over their entire 10-year term as planned. In compliance with Section 24.4.6.4 of the ISO tariff, the ISO followed the LTCRR SFT study steps outlined in Section 4.2.2 of the BPM for the Transmission Planning Process to determine whether there are any existing released LT CRRs that could be at risk and for which mitigation measures should be developed. Based on the results of this analysis, the ISO determined in December of 2022 that there are no existing released LT CRRs “at-risk” that require further analysis. Thus, the transmission projects and elements approved in the 2022-2023 Transmission Plan did not adversely impact feasibility of the existing released LT CRRs. Hence, the ISO did not evaluate the need for additional mitigation solutions.

6.3 Frequency Response Assessment and Data Requirements

As penetration of renewable resources increases, conventional synchronous generators are being displaced with renewable resources using converter-based technologies. Given the materially different operating characteristics of renewable generation, this necessitates broader consideration of a range of issues in managing system dispatch and maintaining reliable service across the range of operating conditions. One of the primary concerns is that there be adequate frequency response from inverter-based resources (IBR) when unplanned system outages and events occur.

Over past planning cycles, the ISO conducted a number of studies to assess the adequacy of forecast frequency response capabilities, and those studies also raised broader concerns with the accuracy of the generation models used in the analysis. Inadequate modeling not only impacts frequency response analysis, but can also impact dynamic and voltage stability analysis as well.

In the subsections below, the progress achieved and issues to be considered going forward have been summarized, as well as the background setting the context for these efforts and the study results.

6.3.1 Frequency Response Methodology & Metrics

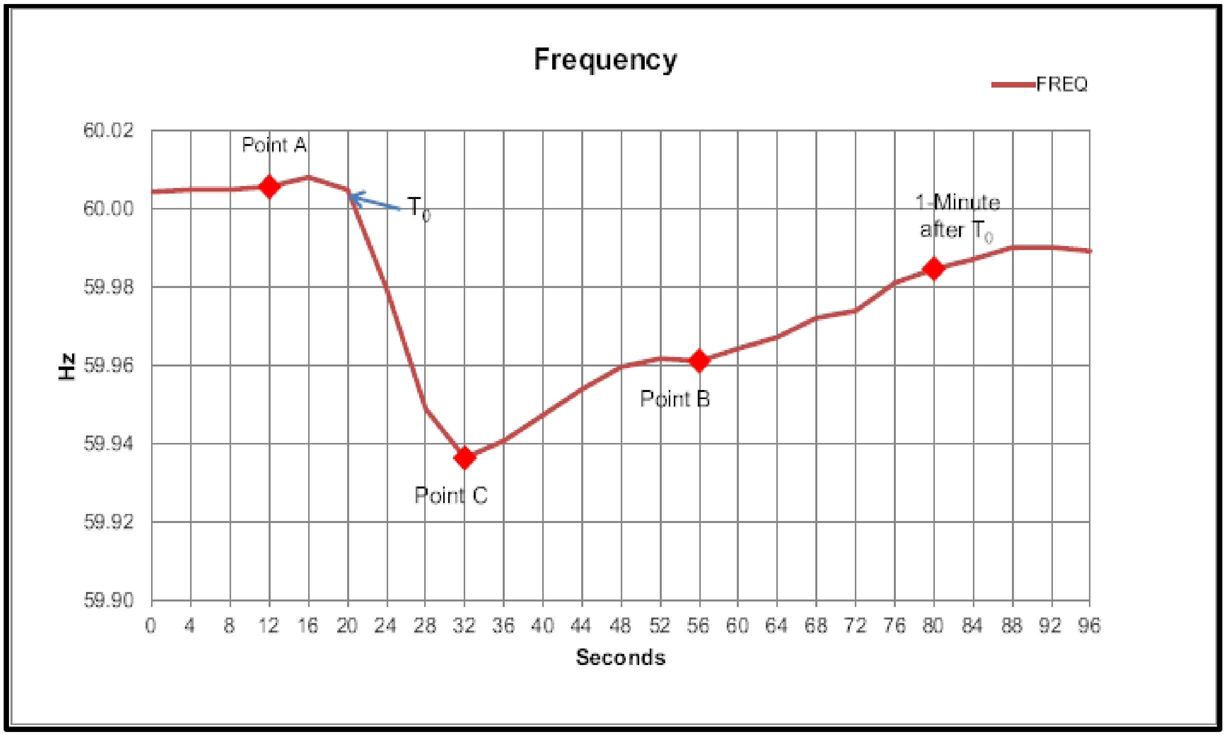
The ISO's most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued on in subsequent years, using the latest dynamic stability models. In this planning cycle, the potential impact of inverter-based resources (IBR), particularly battery energy storage systems (BESS) as a means of aiding frequency response, was investigated.

Background on Frequency Response and Frequency Bias Setting Methodology

NERC has established the methodology for calculating frequency response obligations (FRO) outlined in Reliability Standard BAL-003-2 (Frequency Response and Frequency Bias Setting). A balancing authority's FRO is determined by first defining the FRO of the interconnection as a whole, which is referred to as the interconnection frequency response obligation (IFRO). The methodology then assigns a share of the total IFRO to each balancing authority based on its share of the total generation and load of the interconnection. The IFRO of the WECC Interconnection is determined annually based on the largest potential generation loss, which is the loss of two units of the Palo Verde nuclear generation station (2,740 MW). This is a credible outage that results in the most severe frequency excursion post-contingency.

A generic system disturbance that results in frequency decline, such as the loss of a large generating facility, is illustrated in Figure 6.3-1. Pre-event period (Point A) represents the system frequency prior to the disturbance with T_0 as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 6.3-1: Illustration of Primary Frequency Response



The system frequency performance is acceptable when the frequency nadir post-contingency is above the set point for the first block of the under-frequency load shedding relays, which is set at 59.5 Hz.

The Interconnection Frequency Response Obligation changes from year to year primarily as the result of the changes in the statistical frequency variability during actual disturbances, and statistical values of the frequency nadir and settling frequency observed in the actual system events. Allocation of the Interconnection FRO to each balancing authority also changes from year to year depending on the balancing authority's portion of the interconnection's annual generation and load. This year NERC has maintained the 2016 IFRO value of 858 MW/0.1 Hz be retained for the present operating year. The ISO's share of this obligation remains at 257.4 MW/0.1 Hz.

More conventional synchronous generators are being displaced with renewable resources. This has a significant effect on frequency response. Most of the renewable resources coming online are wind and solar photovoltaic (PV) units that are inverter-based and do not have the same inherent capability to provide inertia response or frequency response to frequency changes as conventional rotating generators. Unlike conventional generation, inverter-based renewable resources must specifically have a dedicated control mechanism to provide inertia response to arrest frequency decline following the loss of a generating resource and to increase their MW output. When a frequency response characteristic is incorporated into IBR control parameters, the upward ramping control characteristic is only helpful if the generator is dispatched at a level that has headroom remaining. As more wind and solar resources displace conventional synchronous generation, the mix of the remaining synchronous generators may not be able to adequately meet the ISO's FRO under BAL-003-2 for all operating conditions.

The most critical condition when frequency response may not be sufficient is when large amounts of renewable resources are online with high output concurrently with a low system load. In such cases conventional resources that otherwise would provide frequency response are not committed. Curtailment of renewable resources either to create headroom for their own governor response, or to allow conventional resources to be committed at a minimum output level, is a potential solution but undesirable from an emissions and cost perspective.

Generation Headroom

One operating condition that is important for frequency response studies is the headroom of the units with responsive governors. The headroom is defined as a difference between the maximum capacity of the unit and the unit's output. For a system to react most effectively to changes in frequency, enough total headroom must be available. Block loaded units, units at maximum capacity and units that don't respond to changes in frequency have no headroom.

The ratio of generation capacity that provides governor response to all generation running on the system is used to quantify overall system readiness to provide frequency response. This ratio is introduced as the metric Kt[81]; the lower the Kt, the smaller the fraction of generation that will respond. The exact definition of Kt has not been standardized.

For the ISO studies, the comparable metric is defined as the ratio of power generation capability of units with responsive governors to the MW capability of all generation units. For units that don't respond to frequency changes, power capability is defined as equal to the MW dispatch rather than the nameplate rating because these units will not contribute beyond their initial dispatch.

Rate of Change of Frequency (ROCOF)

- ROCOF is defined as the rate of change of frequency and is proportional to power imbalance during a system disturbance. The ROCOF value is most responsive immediately after a contingency and is increasingly being used by the industry to gauge the severity of the event and the ability of connected generators to respond in a timely manner to arrest excessive frequency excursions. ROCOF is particularly important as it anticipates the magnitude of frequency changes and in real time can be used to signal and react quickly to excessive frequency excursions.
- ROCOF is difficult to accurately measure post-contingency as the change in frequency is inherently noisy with multiple slope profiles potentially resulting in a wide margin of error. Despite this challenge, the ROCOF is a good predictor of system response to a bulk

[81] Undrill, J. (2010). Power and Frequency Control as it Relates to Wind-Powered Generation. LBNL-4143E. Berkeley, CA: Lawrence Berkeley National Laboratory

system frequency event. When reliably measured, it also provides a good means of ranking contingencies in terms of severity.

6.3.2 FERC Order 842

On February 15, 2018, FERC issued Order 842 that requires newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. Per that Order, all generators including wind, solar and BESS generators that execute an LGIA on or after May 15, 2018 are required to provide frequency response.

6.3.3 2021-2022 Transmission Plan Study

In the prior 2021-2022 transmission planning cycle, the frequency response was assessed and it was determined that the Frequency Response Obligation (FRO) required from ISO was being met. Particular focus was centered on IBR contribution to that response. The IBR units with frequency regulation turned on with available headroom all cause a higher increase in response than would otherwise be provided.

6.3.4 2022-2023 Transmission Plan Study

As in the 2021-2022 transmission planning process, this study is to re-assess the frequency response of the ISO system to a dual Palo Verde unit outage. Once again an emphasis is being placed on the frequency response provided by IBR resources.

Solar and wind plants are IBR but are typically operated so that all energy captured from the wind and the sun is converted to electrical energy and fed into the power system. These units typically do not operate at sub-optimal capability and thus have no headroom available for when a frequency response event occurs.

BESS plants cyclically charge and discharge on an intra-day basis. This energy can be readily modulated during system events to help minimize significant frequency deviations. New plants coming on-line as per FERC Order 842 will have frequency regulation. If enabled and with enough diversity between charging and discharging plants, BESS units can help support the system during significant frequency events.

The spring off-peak case was chosen as there is a lower number of conventional gas units in operation. This case has a high proportion of solar plants on-line with most BESS plants operating in charging mode. IBR plants are those with a ‘repc_a’ plant controller models. Turning off frequency control for these units consists of changing the up and down frequency gains to zero.

The study scenarios are summarized in Table 6.3-1. The study results for the baseline scenarios and the sensitivity study scenarios are illustrated in Figures 6.3-2 through 6.3-5.

Table 6.3-1: Study Scenarios for Frequency Response Study in the 2022-2023 TPP

	Study Scenarios				
	SC1	SC2	SC3	SC4	SC5
PFR enabled for existing IBRs?	No	Yes	Yes	Yes	Yes
Headroom	Existing	Existing	10% BESS units	Min CAISO spinning reserve	Min CAISO spinning reserve
Existing IBRs and other gens droop	5%	5%	5%	5%	5%
Existing IBRs and other gens deadband (Hz)	±0.036	±0.036	±0.036	±0.036	±0.036

Scenario 1 is the reference against which to compare all others, where all existing IBR plants have frequency regulation shut off in the plant controller model.

Scenario 2 has all IBR plant frequency regulation turned on. This scenario is similar to that of the normal 2027 and 2032 base case and with unmodified dynamic models. Figure 6.3-3 shows the resultant 2027 and 2032 system frequency events with reference to Scenario 1. Both 2032 profiles show a marked improvement over that of 2027. The nadir is at 0.131 Hz and 0.153 Hz higher for Scenario 2 for 2027 and 2032 results. The better result in 2032 is explained by the fact that the Palo Verde units are lower proportion of the overall resource total in 2032 compared to 2027 and that there are a higher proportion of IBR plants with frequency control in 2032 than in 2027.

For scenario 3, all new BESS plants were adjusted to a headroom of 10%. In both original Spring Peak cases, the BESS units are in charging mode close to or at their minimum power limit which represents the IBR being in full charging mode. For this scenario all BESS units were re-dispatched using ISO generation to achieve 10% headroom. The net result is that there is a similar response profile for both scenarios 3 and scenario 1 (Figure 6.3-4). A 10% headroom does not inhibit the frequency response as shown in Figure 6.3-4. Both 2027 and 2032 responses with 10% headroom are virtually identical to the case in which all IBRs are all on (Scenario 2).

Scenario 4 is one where all the ISO generation has minimal headroom and is shown in Figure 6.3-5. The 2027 spring off-peak case with all IBR on is marked improved over the same case with ISO at minimum spinning reserve. The 2032 traces on the same plot show a much lesser gap between Scenarios 2 and 4.

Scenario 5 has the ISO BESS units at 10% headroom with the remainder of CAISO at minimum spinning reserve. Figure 6.3-6 shows the comparative results of Categories 3 and 5 for both years surveyed. While a 10% BESS headroom scenario (Scenario 3) does not appreciably influence the frequency response (as per Figure 6.3-4), this restriction clearly shows a significant reduction in the overall frequency response for the Scenario 5.

These results indicate that by enabling the frequency response of the new IBR units coming online, particularly in 2032, the system recovers from frequency events faster and settles at higher frequencies. There is a higher proportion of IBR plants in 2032 which significantly aids the system frequency response when enabled. Also the Palo Verde outage drops a lesser proportion of the overall system generation in 2032 than it does in the 2027 base case.

Figure 6.3-2: 2027 & 2032 Scenarios 1 & 2: System Frequency Response for All IBR Frequency Control On and Off

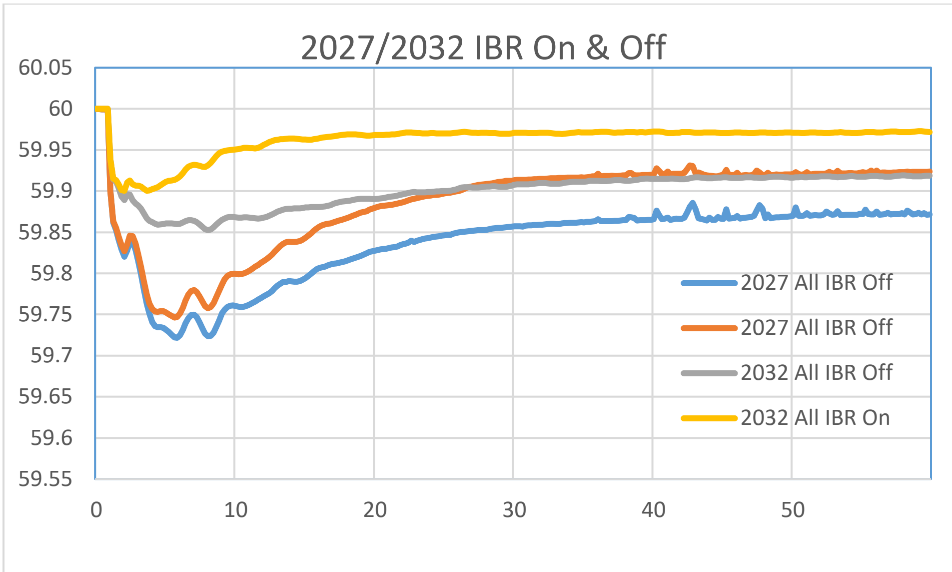


Figure 6.3-3: 2027 & 2032 Scenarios 2&3: System Frequency for all IBR Plants On and BESS Plants at 10% Headroom

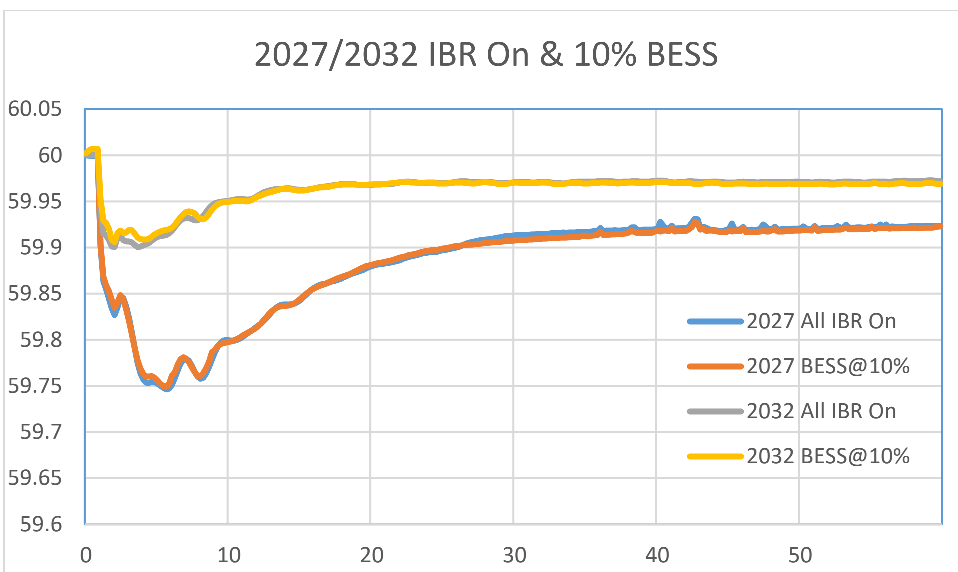


Figure 6.3-4: 2027 & 2023 Scenarios 2 &4: System Frequency for all IBR Plants On and the ISO at Minimum Spinning Reserve

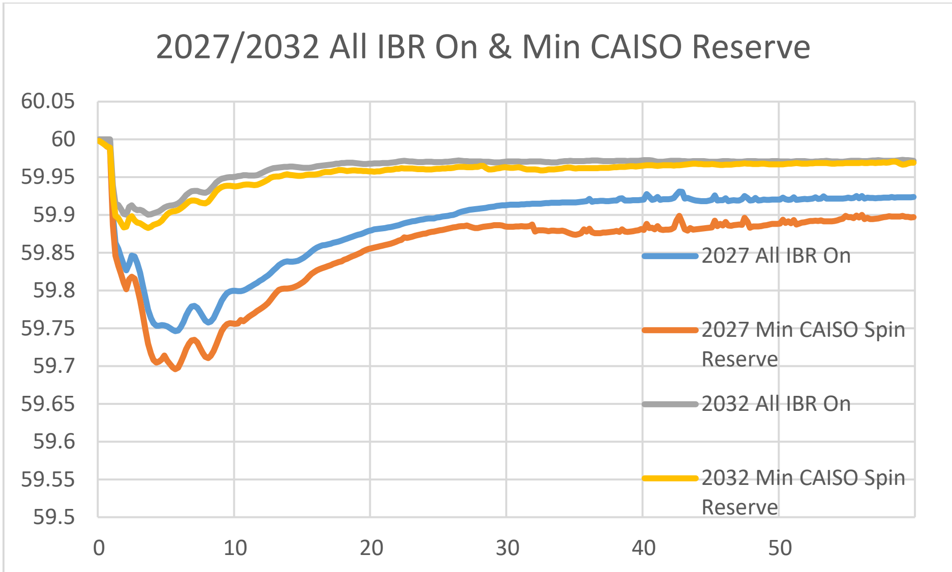
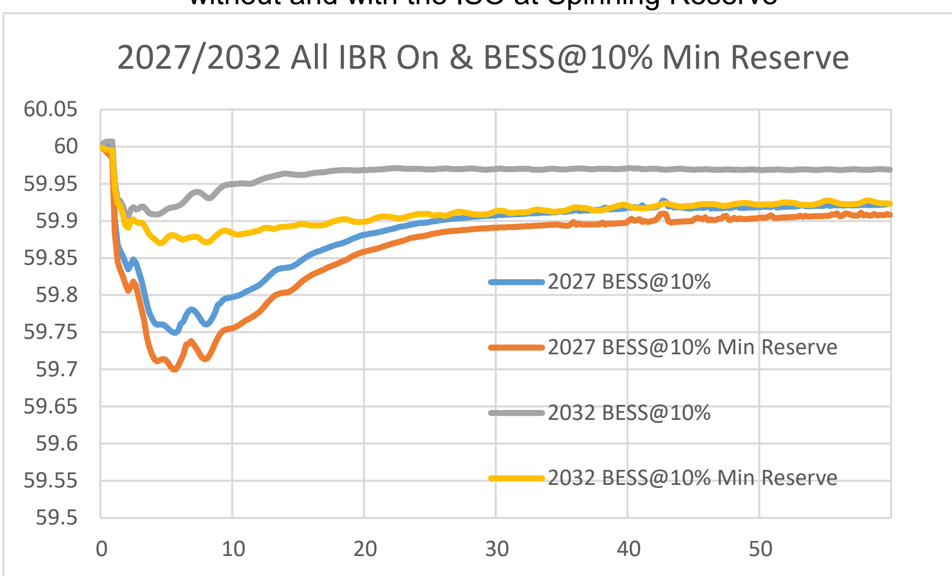


Figure 6.3-5: 2027 & 2023 Scenario 3 & 5: System Frequency Response with BESS@10% without and with the ISO at Spinning Reserve



Conclusions and recommendations from the 2022-2023 transmission planning process study

This study indicates that the ISO system response to major frequency events such as two Palo Verde units improves when IBRs have headroom, also when in charging mode (ample headroom), and have frequency response enabled.

The studies illustrated that the ISO is forecasted to meet its Frequency Response Obligation (FRO) with the frequency response of new IBRs enabled per FERC Order 842. It is sufficient to meet FRO just by enabling the PFR even with current values for droop and deadband.

A number of existing IBRs connected to the ISO footprint have primary frequency response (PFR) capability but there are still a significant number of units for which the PFR capabilities of the IBRs are not enabled. Considering the subset of existing IBRs that are BESS units with frequency response enabled and that all future IBR plants will have frequency response available and enabled, it is expected that the PFR capability of the IBRs would be beneficial to system recovery from frequency events and continue to meet the ISO Frequency Response Obligation (FRO).

6.3.4.1 Progress in Updating and Validating Models

There are various standards and procedures in place for the collection of modeling information from Transmission Owners, developers and their vendors. The ISO also continues to validate existing generator modes as set out in Section 10 of the ISO's Transmission Planning Process business practice manual.[82] A whitepaper released in September 2021 entitled 'Dynamic Model Review Guideline for Inverter based Interconnection Requests'[83] outlines the selection of inverter parameters to ensure interconnection requirements. The later also ensures that frequency response from IBR resources, if enabled, will contribute to arresting abrupt frequency changes.

Validation of system models using simulations that emulate actual major frequency events is presently a process that may be more formally systematized during upcoming planning cycles. This will help ensure that primary frequency response from generators match the expected response and helps align operational results with planning studies. Also this provides an opportunity to determine that existing load models behave as realistically as possible.

[82] https://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

[83] http://www.caiso.com/Documents/InverterBasedInterconnectionRequestsIBRDynamicModelReviewGuideline.pdf

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Chapter 7

7 Special Reliability Studies and Results

In addition to the mandated analysis framework set out in the ISO's tariff described above, the ISO has also pursued in past transmission planning cycles a number of additional "special studies" in parallel with the tariff-specified study processes. This is done to help prepare for future planning cycles that reach further into the issues emerging through the transformation of the California electricity grid. These studies are provided on an informational basis only and are not for identifying needs or mitigations for ISO Board of Governor approval. A number of those studies have now been incorporated into analysis in Chapter 3 exploring resource portfolio scenarios, or are now being conducted on an annual basis and are in Chapter 6. In the 2022-2023 transmission planning cycle, the ISO performed the following two "special studies":

- Transmission reliability study for the LA Basin and San Diego-Imperial Valley local capacity areas with reduced reliance on Aliso Canyon gas storage; and
- Policy-driven assessment of the high electrification sensitivity scenario.

Only the summary of key findings is included in this chapter for the transmission reliability study for the reduced reliance on Aliso Canyon gas storage. For further details of the study findings, please refer to Appendix K of the Transmission Plan.

7.1 Information Only, Transmission Reliability Study of the LA Basin and San Diego-Imperial Valley Local Capacity Areas with Reduced Reliance on Aliso Canyon Gas Storage

The Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) located in the Santa Susana Mountains of Los Angeles County is the largest natural gas storage facility in California. The facility provides gas support to the core and non-core customers, including electric generation located in the LA Basin between the ISO and the Los Angeles Department of Water and Power (LADWP) Balancing Authority Areas. On October 23, 2015, Southern California Gas Company (SoCalGas) crews discovered a leak at the natural gas storage well at Aliso Canyon. The leak was stopped and the well was sealed in February 2016. Subsequently, the California Public Utility Commission (CPUC)[84] has capped the inventory level at Aliso Canyon at various levels, and most recently, at 41.16 Bcf[85] in November 2021.

In the 2022-2023 transmission planning cycle, the ISO undertook an information only transmission study to evaluate the potential reliability impacts to the transmission facilities in the

[84] The CPUC has jurisdiction over the above ground infrastructure beginning where the storage facility connects to the pipeline, or "at the wellhead." In addition, the CPUC has jurisdiction over the recovery of costs related to the storage facility as well as ensuring that Southern California Gas Company provides safe, reliable service at just and reasonable rates. The California Geologic Energy Management Division, (CalGEM), has primary jurisdiction over Aliso Canyon's underground facilities, and decided the maximum allowable operating pressure in the field to be 2,926 psi, which translates to an inventory of 68.6 billion cubic feet (Bcf) of natural gas.

[85] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF

LA Basin and to some extent the San Diego-Imperial Valley local capacity areas in the ISO Balancing Authority Area due to strong interaction between these two areas. The ISO worked with the CPUC to obtain potential ranges of gas-fired generation capacity impacts, and to the extent possible, the generating units that are associated with these ranges.[86] The ISO also evaluated various potential transmission upgrades needed to maintain transmission reliability in the LA Basin and to some extent the San Diego-Imperial Valley area, as necessary, based on applicable NERC, WECC and ISO reliability standards. These study results are for informational purposes only at this time as further confirmation is needed on the specific gas generating units that may need to be curtailed under the summer peak load condition without Aliso Canyon gas storage availability. In addition, further clarity on the future operational need of Aliso Canyon gas storage from the CPUC would be needed for the ISO to plan for specific electric transmission upgrades that may needed.

The ISO presented the following study scope to the stakeholders at the July 6, 2022 meeting. The following section provides further details on the study scope.

7.1.1 Study Scope

Study Objective

- Performing the local reliability assessment for the LA Basin and San Diego-Imperial Valley areas in the absence of Aliso Canyon gas storage.

Study Scopes

- Performing reliability assessments for the LA Basin and San Diego-Imperial Valley local capacity requirement areas with the gas-fired generation curtailment due to absence of the Aliso Canyon gas storage; and
- Identifying reliability concerns and evaluating potential transmission upgrade options.

The single line diagram of the study areas of the LA Basin and San Diego-Imperial Valley local capacity areas is illustrated in Figure 7.1-1.

86 The list of gas-fired generation that was curtailed for the study is obtained from FTI Consulting (CPUC's consultant) study that is part of the CPUC Aliso Canyon OII Phase 3 (I.17-02-002), as further explained below.

Figure 7.1-1: LA Basin and San Diego-Imperial Valley Local Capacity Areas

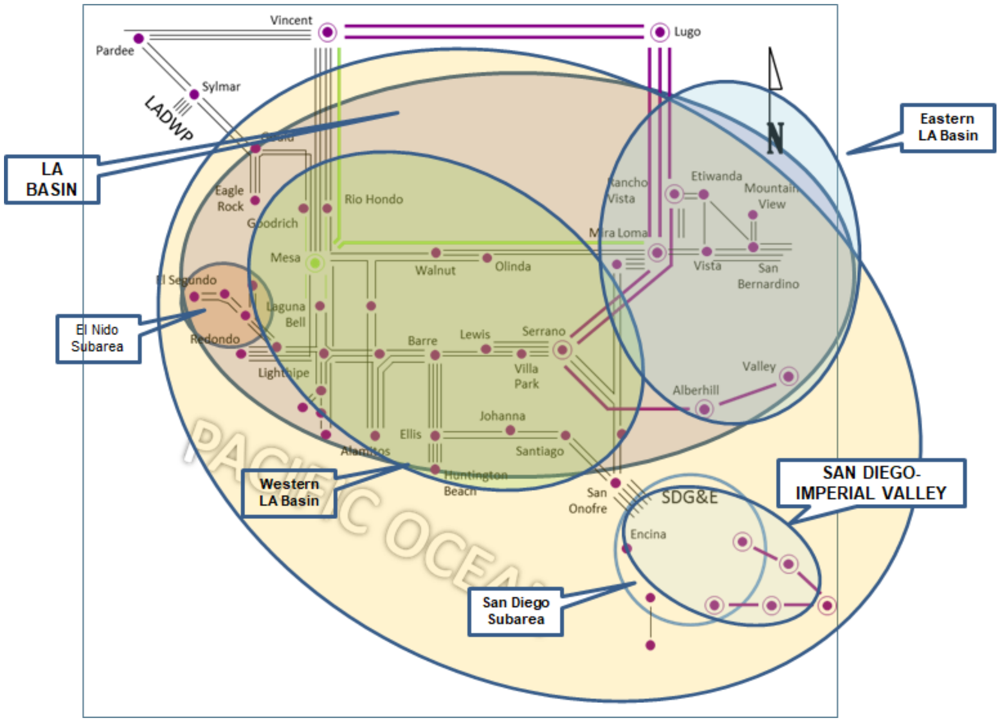
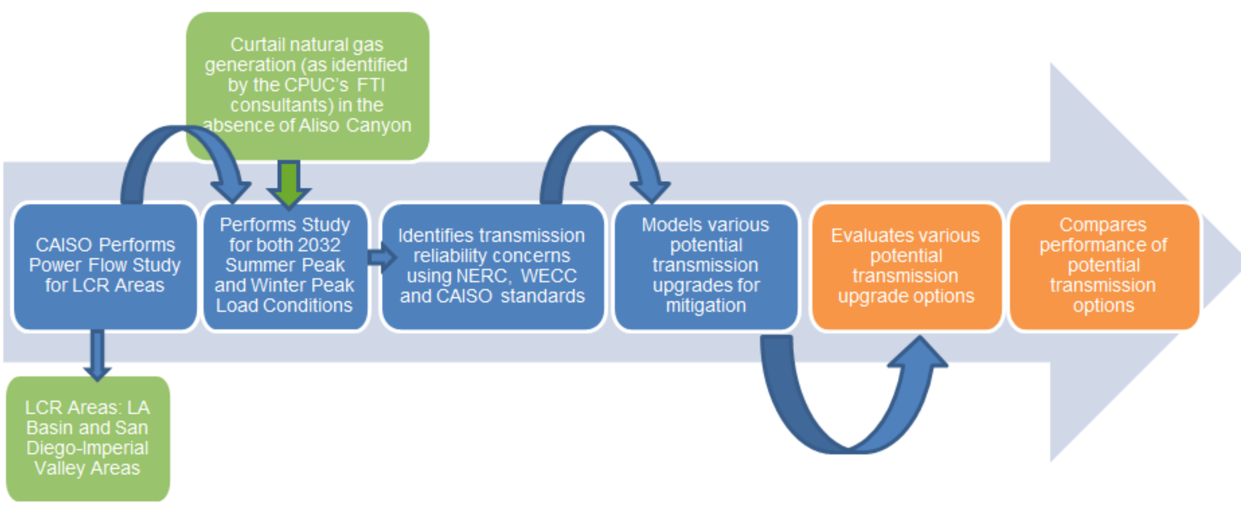


Figure 7.1-2 provides the summary of the study process used for the assessment.

Figure 7.1-2: Summary of Study Process



LCR Area: Local Capacity Requirement Area

A summary of the study base cases is provided in Table 7.1-1.

Table 7.1-1: Study Base Cases

	Power Flow Cases	Study Case Descriptions
1	2032 Summer peak	Models 1-in-10 AAEE 2 & AAFS 4 demand with Additional Transportation Electrification (ATE) forecasts
2	2032 Winter peak	67% of the Summer peak load condition

Gas-fired Generation Curtailment

The list of gas-fired generation that was curtailed for the study is obtained from FTI Consulting (CPUC's consultant) study that is part of the CPUC Aliso Canyon OII Phase 3 (I.17-02-002) is provided in Appendix K, Section K1. A summary of the number of generation facilities and the total curtailment capacity for the facilities in the ISO Balancing Authority Area is provided in Table 7.1-2.

Table 7.1-2: Number of Generator Facilities and Total Curtailment Capacity

PTO Area	Number of Generation Facilities	Total Curtailment (MW)
SCE	41	3,083
SDG&E	15	645
Total	56	3,728

7.1.2 Study Process

- Both summer peak load and winter peak load assessments were performed for the ten-year study cases (i.e., 2032 summer peak and winter peak);
- As part of the study, the ISO identified potential reliability concerns due to curtailment of gas-fired generation in the LA Basin and San Diego-Imperial Valley LCR areas in the absence of Aliso Canyon gas storage; and
- The ISO also evaluated various potential transmission upgrade options to mitigate identified reliability concerns:
  - As part of this process, the ISO leveraged the information from the potential transmission upgrades that were identified in the 20-Year Transmission Outlook[87] as a guide in evaluating potential mitigations in the LA Basin and San Diego LCR areas.

[87] http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf

7.1.3 Study Results

The following is a summary of information only reliability study results:

- Extensive thermal overloading concerns under critical contingencies in the LA Basin and San Diego areas under summer peak load conditions;
- Several IID transmission facilities are also impacted due to contingencies in the San Diego-Imperial Valley area;
- 2032 Winter peak load conditions did not result in transmission reliability concerns in the LA Basin and San Diego-Imperial Valley area, provided that the remaining gas-fired generation resources are available; and
- As transportation and building fuel substitution become more electrified in the future, the winter peak load is also increasing (winter peak load for 2035 increases 6% over the 2032 winter peak load (73% of summer peak vs. 67% summer peak).

For further details on specific transmission facilities and identified reliability concerns, please refer to the report in Appendix K, Section K2.

7.1.4 Transmission Alternatives

A summary of transmission the alternatives that were evaluated for efficacy in mitigating the identified transmission reliability constraints is provide in Table 7.1-3.

Table 7.1-3: Transmission Alternatives

Options	Description of Alternatives	Areas
1A	• Diablo South Multi-Terminal HVDC VSC Line (2000 MW at Diablo Canyon, 1000 MW at Alamitos and 1000 MW at Huntington Beach; • Additional upgrades in LA Basin (La Fresa-Hinson 230 kV, South of Ellis 230 kV lines); and • Imperial Valley-N.Gila #2 500 kV line, Sycamore-Suncrest 230 kV #3 line, Suncrest 500/230 kV #3 transformer, Miguel 500/230 kV #3 transformer.	Western LA Basin & San Diego
1B	• Diablo South Multi-Terminal HVDC VSC Line (same as in Option 1A); • Imperial Valley – N.Gila 500 kV #2 line; and • Alberhill – Suncrest 500 kV HVDC VSC line (1000 MW).	Western and Eastern LA Basin, San Diego
2A	• Diablo South Multi-Terminal HVDC VSC Line (2000 MW at Diablo Canyon, 1000 MW at Redondo Beach, 1000 MW at Encina).	Western LA Basin and San Diego
2B	• Diablo South (same as Option 2A); • Third Sycamore-Suncrest 230 kV line; and • Fourth Serrano AA 500/230 kV transformer	Western LA Basin and San Diego
2C	• Diablo South (same as Option 2A); and • Alberhill-Suncrest HVDC VSC Line (1000 MW).	Western LA Basin and San Diego

Options	Description of Alternatives	Areas
3	• Diablo South (2000 MW at Diablo Canyon, 500 MW at Redondo Beach, 750 MW at Alamitos, 750 MW at San Onofre).	Western LA Basin and San Diego
4	• Vincent-Del Amo HVDC VSC line (1000 MW).	Western LA Basin
5	• Imperial Valley – Serrano HVDC VSC line (2000 MW).	San Diego, Western LA Basin
6	• Devers – La Fresa HVDC VSC line (1000 MW).	Eastern and Western LA Basin
7A	• Imperial Valley-Del Amo HVDC VSC line (2000 MW); and • Imperial Valley-N.Gila #2 500 kV line	San Diego Western LA Basin
7B	• Option 7A, plus the following upgrades: o Additional upgrades in the LA Basin (La Fresa-Hinson 230 kV line, Lighthipe-Mesa 230 kV line, Mesa-Redondo 230 kV, Midway-Whirlwind (check for applicability and adequacy of Path 26 RAS); o Serrano AA 500 kV Bank #4; o Additional Suncrest and Miguel 500/230 kV transformer banks; and o Additional dynamic reactive support in San Diego.	Western LA Basin San Diego
8A	• Multi-terminal HVDC VSC (Imperial Valley (2000 MW)-Inland (normal flow at 1000 MW with converter capability up to 2000 MW for emergency condition)-Del Amo (1000 MW normal flow with converter capability up to 2000 MW for emergency condition)), plus the following upgrades: o Del Amo-Mesa 500 kV line (new); o Del Amo-Serrano 500 kV line (new); and o Del Amo new 500 kV substation with 3 new AA-banks.	Western LA Basin San Diego
8B	• Multi-terminal HVDC VSC (Imperial Valley (2000 MW) – Sycamore Canyon (1000 MW normal flow with converter capability up to 2000 MW for emergency condition) - Del Amo (1000 MW normal flow with converter capability up to 2000 MW for emergency condition)), plus the following upgrades: o Del Amo-Mesa 500 kV line (new); o Del Amo-Serrano 500 kV line (new); and o Del Amo new 500 kV substation with 3 new AA-banks.	Western LA Basin San Diego

For further details on each transmission alternative's performance and its effectiveness in mitigating identified reliability concerns, please refer to Appendix K, Section K3.

Conclusions

The study is an informational study to continue the assessment of transmission alternatives that may potentially be required with reduced reliance on Aliso Canyon gas storage. Further work on the input assumptions on the impact of available gas in the LA Basin is required for the summer months when the load is at peak energy demand.

The following provides a summary and comparison analysis of the studies undertaken in this informational assessment:

- Alternatives 1A, 2B and 2C are effective at mitigating reliability concerns in the LA Basin and San Diego-Imperial Valley areas.
    - These alternatives include a multi-terminal HVDC VSC line south of Diablo Canyon to the LA Basin and San Diego areas. The studies include power flow analysis only. The ISO is in the process of assessing applicable dynamic models that will be required for dynamic stability analysis.
    - The alternatives take advantage of locating the terminal HVDC VSC lines where once-through cool gas generation retires.
    - The alternatives also provide loading relief to Path 26 line flow under contingency conditions.
    - Variation of HVDC VSC terminals to be connected to the LA Basin and San Diego areas were included.
    - Depending on where these terminals are connected to, other transmission upgrades may be required to provide further mitigations.
- Alternatives 7B and 8B are also effective at mitigating reliability concerns in the LA Basin and San Diego-Imperial Valley areas.
    - These alternatives do not provide loading relief to line flows on Path 26 under contingency conditions when compared to alternatives 1A, 2B and 2C. However, these alternatives provide policy-driven benefits of accessing renewable resources in the Imperial Valley Substation.
    - Both of these alternatives include 500 kV HVDC VSC transmission lines in the LA Basin and San Diego-Imperial Valley areas.
    - Alternative 8B provides better performance in mitigating voltage stability concern due to loss of two major 500 kV transmission lines in San Diego areas when compared to Alternative 7B.
    - 500 kV AC alternatives from the Imperial Valley into the LA Basin with an interconnection into the 230 kV at a new 500/230 kV station at North of SONGS or Inland, as illustrated in Chapter 3 and Appendix, will also provide reduction in local capacity gas requirements in the LA Basin as the HVDC alternatives F have demonstrated.

7.2 Policy Driven Assessment of the High Electrification Sensitivity Scenario

In the 2022-2023 transmission planning cycle, the ISO undertook a special study to evaluate the potential reliability impacts to the transmission facilities based on a high electrification scenario. The CEC, in collaboration with the CPUC and the ISO, developed a demand scenario that placed a greater emphasis on electrification than was embedded within the CEC's 2021 IEPR energy demand forecast. The CPUC also developed a resource portfolio based upon the high electrification scenario. The CEC and CPUC provided the high electrification scenario load forecast and resource portfolio to the ISO during the course of summer 2022. For this effort, the ISO engaged stakeholders via webinar meetings that were part of the ISO transmission planning process as well as performed reliability assessment, policy analysis and production cost simulation for the high electrification sensitivity scenario.

The following study assumptions were included as part of the high electrification sensitivity scenario:

- 2035 for study year;
- 2021 Integrated Energy Policy Report (IEPR) Additional Transportation Electrification demand scenario; and
- 30 MMT High Electrification policy-driven sensitivity portfolio.

The study results for the high electrification sensitivity scenario are included in Chapter 2 (Reliability Assessment), Chapter 3 (Policy Assessment) and Chapter 4 (Economic Assessment).

Chapter 8

8 Transmission Project List

8.1 Transmission Project Updates

Table 8.1-1 and Table 8.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous transmission plans, the ISO determined these projects were needed to mitigate identified reliability concerns, interconnect new renewable generation via a location-constrained resource interconnection facility project or enhance economic efficiencies.

Table 8.1-1: Status of Previously Approved Projects Costing Less than $50 M

No	Project	PTO	Transmission Plan Approved [88]	Current Expected In-service date[89]
1	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	2008	In-Service Q4-2022
2	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Kern PP 230 kV Area Reinforcement Project)	PG&E	2010-2011	In-Service Q1-2021
3	Oakland Clean Energy Initiative (Oakland X 115 kV Bus Upgrade)	PG&E	2017-2018	In-Service Q2-2022
4	Palermo – Wyandotte 115 kV Line Section Reconductoring Project	PG&E	2020-2021	In-Service Q3-2021
5	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	2017-2018	In-Service Q4-2022
6	Vaca Dixon Area Reinforcement (Replace Bank 5)	PG&E	2017-2018	In-Service Q3-2022
7	Atlantic 230/60 kV transformer voltage regulator	PG&E	2021-2022	Q2-2026
8	Borden 230/70 kV Transformer Bank #1 Capacity Increase	PG&E	2019-2020	Q4-2027
9	Cascade 115/60 kV No.2 Transformer Project	PG&E	2010-2011	Q4-2024
10	Christie-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	Q2-2028
11	Clear Lake 60 kV System Reinforcement	PG&E	2009	Q4-2028

[88] Additional detail for the projects including cost information and scope can be found in the Transmission Plan in which they were approved. http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx

[89] Draft Transmission Plan in-service dates based on January Transmission Development Forum. Revised draft will be updated based on the in-service dates of the April Transmission Development Forum

No	Project	PTO	Transmission Plan Approved [88]	Current Expected In-service date[89]
12	Coburn-Oil Fields 60 kV system project	PG&E	2017-2018	Q2-2029
13	Contra Costa PP 230 kV Line Terminals Reconfiguration Project	PG&E	2021-2022	Q2-2025
14	Cooley Landing 60 kV Substation Circuit Breaker No #62 Upgrade	PG&E	2021-2022	Q4-2026
15	Coppermine 70 kV Reinforcement Project	PG&E	2021-2022	Q4-2027
16	Cortina 230/115/60 kV Transformer Bank No. 1 Replacement Project	PG&E	2021-2022	Q2-2027
17	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	2018-2019	Q1-2026
18	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project	PG&E	2017-2018	Q3-2025
19	East Marysville 115/60 kV Project	PG&E	2018-2019	Q1-2028
20	East Shore 230 kV Bus Terminals Reconfiguration	PG&E	2019-2020	Q4-2025
21	East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved)	PG&E	2011-2012	Q4-2023
22	Estrella Substation Project	PG&E	2013-2014	Q2-2028
23	Giffen Line Reconductoring Project	PG&E	2018-2019	Q1-2024
24	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	2013-2014	Q4-2023
25	Gold Hill 230/115 kV Transformer Addition Project	PG&E	2018-2019	Q2-2028
26	Herndon-Bullard 115 kV Reconductoring Project	PG&E	2017-2018	Q4-2026
27	Ignacio Area Upgrade	PG&E	2017-2018	Q4-2028
28	Jefferson 230 kV Bus Upgrade	PG&E	2018-2019	Q4-2026
29	Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project	PG&E	2020-2021	Q4-2026
30	Lakeville 60 kV Area Reinforcement	PG&E	2017-2018	Q4-2028
31	Manteca #1 60 kV Line Section Reconductoring Project	PG&E	2020-2021	Q1-2025
32	Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project	PG&E	2021-2022	Q2-2026
33	Maple Creek Reactive Support	PG&E	2009	Q4-2027
34	Metcalf 230 kV Substation Circuit Breaker No# 292 Upgrade	PG&E	2021-2022	2025

No	Project	PTO	Transmission Plan Approved [88]	Current Expected In-service date[89]
35	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	2003	Q4-2027
36	"Midway – Kern PP #2 230 kV Line (Bakersfield-Kern Reconductor)"	PG&E	2013-2014	Q1-2028
37	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Midway 230 kV Bus Section D Upgrade Project)	PG&E	2010-2011	Q2-2025
38	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	2012-2013	Q4-2028
39	Monta Vista 230 kV Bus Upgrade	PG&E	2012-2013	Q3-2025
40	Moraga 230 kV Bus Upgrade	PG&E	2019-2020	Q4-2028
41	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	2010-2011	Q2-2024
42	Moraga-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	On Hold
43	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	2013-2014	Q3-2027
44	Mosher Transmission Project	PG&E	2013-2014	Q4-2027
45	Moss Landing – Las Aguilas 230 kV Series Reactor Project	PG&E	2021-2022	Q4-2026
46	"Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition"	PG&E	2019-2020	Q4-2026
47	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	2017-2018	Q4-2024
48	North Tower 115 kV Looping Project	PG&E	2011-2012	Q1-2030
49	Oakland Clean Energy Initiative (MORAGA 115 KV BUS UPGRADE & BK 3 SW)	PG&E	2017-2018	Q4-2023
50	Oro Loma 70 kV Area Reinforcement	PG&E	2010-2011	Q4-2026
51	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	2015-2016	Q2-2024
52	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	2007	Q1-2025
53	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	2018-2019	Q4-2025
54	Reconductor Delevan-Cortina 230 kV line	PG&E	2021-2022	Q4-2028
55	Reconductor Rio Oso–SPI Jct–Lincoln 115 kV line	PG&E	2021-2022	Q4-2029
56	Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects)	PG&E	2017-2018	Q4-2025
57	Rio Oso 230/115 kV Transformer Upgrades	PG&E	2007	Q4-2025
58	Rio Oso Area 230 kV Voltage Support	PG&E	2011-2012	Q2-2025

No	Project	PTO	Transmission Plan Approved [88]	Current Expected In-service date[89]
59	Salinas-Firestone #1 and #2 60 kV Lines	PG&E	2019-2020	Q4-2026
60	Series Compensation on Los Esteros-Nortech 115 kV Line	PG&E	2021-2022	Q4-2024
61	South of Mesa Upgrade	PG&E	2018-2019	Q2-2027
62	South of San Mateo Capacity Increase	PG&E	2007	Q2-2027
63	Tesla 230 kV Bus Series Reactor project	PG&E	2018-2019	Q4-2023
64	Tesla Substation 230 kV bus section D and circuit breakers 372, 382 and 842 overstress (reactors) TESLA: 230KV BUS REACTORS D - E	PG&E	2018-2019	Q2-2023
65	Tesla Substation 230 kV bus section D and circuit breakers 372, 382 and 842 overstress (reactors) TESLA_230KV BUS REACTORS C – D	PG&E	2018-2019	Q4-2023
66	Tie line Phasor Measurement Units	PG&E	2017-2018	Q4-2026
67	Tulucay-Napa #2 60 kV Line Capacity Increase	PG&E	2019-2020	Q4-2025
68	Tyler 60 kV Shunt Capacitor	PG&E	2018-2019	Q2-2026
69	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	2017-2018	Q2-2026
70	Vasona-Metcalf 230 kV Line Limiting Elements Removal Project	PG&E	2021-2022	Q2-2025
71	Vierra 115 kV Looping Project	PG&E	2010-2011	Q3-2025
72	Warnerville-Bellota 230 kV line reconductoring	PG&E	2012-2013	Q2-2024
73	Weber-Mormon Jct 60 kV Line Section Reconductoring Project	PG&E	2021-2022	Q2-2026
74	Wilson 115 kV Area Reinforcement	PG&E	2010-2011	Q1-2028
75	Wilson-Le Grand 115 kV line reconductoring	PG&E	2012-2013	Q4-2023
76	Wilson-Oro Loma 115 kV Line Reconductoring	PG&E	2019-2020	Q4-2028
77	Moorpark-Pardee No. 4 230 kV Circuit	SCE	2018	In Service May-2022
78	Devers 230 kV Reconfiguration Project	SCE	2021-2022	Jun-25
79	Laguna Bell - Mesa No. 1 230 kV Line Rating Increase Project	SCE	2021-2022	Apr-24
80	Lugo – Victorville 500 kV Upgrade (SCE portion)	SCE	2017	Jan-25
81	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	2008	Dec-25
82	Method of Service for Wildlife 230/66 kV Substation	SCE	2007	Oct-27

No	Project	PTO	Transmission Plan Approved [88]	Current Expected In-service date[89]
83	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	2020	Jun-25
84	Tie line Phasor Measurement Units	SCE	2017-2018	Dec-25
85	Victor 230 kV Switchrack Reconfiguration	SCE	2021-2022	Apr-25
86	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	2013-2014	Close-Out
87	Rose Canyon-La Jolla 69 kV T/L	SDG&E	2013-2014	Completed
88	2nd Escondido-San Marcos 69 kV T/L	SDG&E	2013-2014	Feb-23
89	Reconductor TL 605 Silvergate – Urban	SDG&E	2015-2016	Jun-24
90	Sweetwater Reliability Enhancement	SDG&E	2012-2013	Nov-27
91	TL623C Reconductor (San Ysidro - Otay Tap)	SDG&E	2017-2018	Feb-29
92	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	2013-2014	Jun-26
93	TL644, South Bay-Sweetwater: Reconductor	SDG&E	2010-2011	May-22
94	TL649D Reconductor (San Ysidro - Otay Lake Tap)	SDG&E	2017-2018	Dec-24
95	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	2012-2013	Nov-22
96	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	2013-2014	Nov-26
97	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	2011-2012	Feb-23
98	Tie Line Phasor Measurement Units	VEA	2017-2018	Jun-23
99	IID S-Line Upgrade	Citizens Energy	2017-2018	2023

Table 8.1-2: Status of Previously-Approved Projects Costing $50 M or More

No	Project	PTO	Transmission Plan Approved	Current Expected
1	Kern PP 115 kV Area Reinforcement	PG&E	2011-2012	Aug-23
2	Lockeford-Lodi Area 230 kV Development	PG&E	2012-2013	Jun-23
3	Martin 230 kV Bus Extension	PG&E	2014-2015	May-23
4	Midway – Kern PP #2 230 kV Line	PG&E	2013-2014	Jun-23
5	New Collinsville 500 kV substation	PG&E	2021-2022	Q4-2028
6	New Manning 500 kV substation	PG&E	2021-2022	Q4-2028
7	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)	PG&E	2012-2013	On Hold
8	Red Bluff-Coleman 60 kV Reinforcement (Original project was the "Cottonwood-Red Bluff No2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project" approved in 2010-2011 Transmission Plan. The project was rescoped and renamed in 2017-2018 Transmission Plan.)	PG&E	2017-2018	Dec-23
9	San Jose Area HVDC 230 kV Line (Newark - NRS)	PG&E	2021-2022	Q4-2028
10	San Jose Area HVDC 500 kV Line (Metcalf – San Jose)	PG&E	2021-2022	Q4-2028
11	Table Mountain Second 500/230 kV Transformer	PG&E	2021-2022	Q4-2027
12	Vaca Dixon Area Reinforcement (Original project was the "Vaca – Davis Voltage Conversion Project" approved in 2010-2011 Transmission Plan. The project was rescoped and renamed in 2017-2018 Transmission Plan)	PG&E	2017-2018	Jul-23
13	Wheeler Ridge Junction Substation	PG&E	2013-2014	On Hold
14	Alberhill 500 kV Method of Service	SCE	2009	Jun-23
15	Antelope 66 kV Circuit Breaker Duty Mitigation Project	SCE	2021-2022	Jul-05
16	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	2012-2013	Dec-23
17	Lugo-Mohave series capacitor upgrade	SCE	2012-2013	Dec-23
18	Mesa 500 kV Substation Loop-In	SCE	2013-2014	In-Service May-2022
19	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)	SDG&E	2010-2011	Nov-23
20	Artesian 230 kV Sub & loop-in TL23051	SDG&E	2013-2014	Jun-23
21	GLW/VEA Area Upgrades	VEA/GLW	2021-2022	TBD
22	Delaney-Colorado River 500 kV line	DCR Transmission	2013-2014	Apr-23
23	Gates 500 kV Dynamic Voltage Support	LS Power	2018-2019	Jun-23
24	Round Mountain 500 kV Dynamic Voltage Support	LS Power	2018-2019	Dec-23

8.2 Transmission Projects found to be needed in the 2022-2023 Planning Cycle

In the 2022-2023 transmission planning process, the ISO determined that 24 transmission projects were needed to mitigate identified reliability concerns; 21 policy-driven projects were needed to meet the GHG reduction goals and no economic-driven projects were found to be needed. Summaries of the needed projects are in Table 8.2-1 and Table 8.2-2.

A list of projects that came through the 2022 Request Window can be found in Appendix E.

Additional details of new projects can be found in Appendix H.

Table 8.2-1: New Reliability Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost (in millions of dollars)
1	Garberville area reinforcement project	Humboldt	2032	204
2	Tulucay-Napa #2 60 kV line Reconductoring project	NCNB	2028	14.6
3	Santa Rosa 115 kV lines Reconductoring project	NCNB	2028	74
4	Tesla 115 kV Bus Reconfiguration Project	CVLY	2030	55
5	Banta 60 kV Bus Voltage Conversion	CVLY	2024	17.5
6	Metcalf 230/115 kV Transformers Circuit Breaker Addition	GBA	2026	15
7	South Bay Area Limiting Elements Upgrade	GBA	2027	11
8	Redwood City Area 115 kV System Reinforcement	GBA	2030	110.8
9	Lone Tree – Cayetano – Newark Corridor Series Compensation	GBA	2027	25
10	Pittsburg 115 kV Bus Reactor project	GBA	2032	26
11	Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation	Fresno	2024	1.6
12	Los Banos 70 kV Area Reinforcement Project	Fresno	2029	60
13	Los Banos 230 kV Circuit Breaker Replacement	Fresno	2032	66
14	Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	Fresno	2032	184
15	North East Kern 115 kV Line Reconductoring Project	Kern	2032	256
16	Mesa 230/115 kV spare transformer	CCLP	2032	24

17	Barre 230 kV Switchrack Conversion to Breaker-and-a-Half	SCE - Main	2026	45
18	Mira Loma 500 kV Circuit Breaker Upgrade	SCE - Main	2026	10
19	Serrano 4AA 500/230 kV Transformer Bank Addition	SCE - Main	2027	120
20	Sylmar Transformer Replace	SCE - Main	2026	23
21	Antelope-Whirlwind 500 kV Line Upgrade Project	SCE - Main	2025	6
22	Coolwater 1A 230/115 kV Bank Project	SCE - NOL	2026	47
23	Control 115 kV Shunt Reactor	SCE - NOL	2026	4
24	Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Project	SDG&E	2032	375

Table 8.2-2: New Policy-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost (in millions of dollars)
1	Borden-Storey 230 kV 1 and 2 Line Reconductoring	Fresno	2032	$50
2	Henrietta 230/115 kV Bank 3 Replacement	Fresno	2032	$20
3	Beatty 230 kV	VEA/GLW	2027	$155
4	Lugo–Victor–Kramer 230 kV Upgrade	North of Lugo	2032	$482
5	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE Eastern	2028	$50
6	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE Eastern	2028	$140
7	Devers-Valley 500 kV 1 Line Upgrade	SCE Eastern	2028	$40
8	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE Eastern	2028	$60
9	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE Eastern	2031	$65
10	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE Eastern	2028	$18
11	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE Eastern	2031	$13
12	Mira Loma-Mesa 500 kV Underground Third Cable	SCE Metro	2026	$30
13	Imperial Valley–North of SONGS 500 kV Line and Substation	SDG&E	2034	$2,288
14	North of SONGS–Serrano 500 kV line	SDG&E and SCE Metro	2034	$503

15	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE Metro	2033	$1,125
16	North Gila–Imperial Valley 500 kV line	SDG&E (Potential Joint Project with IID)	2028	$340
17	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	2032	$27
18	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	2032	$21
19	Reconductor TL680C San Marcos-Melrose Tap	SDG&E	2032	$28
20	3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	2032	$8
21	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	2032	$60

There are no new economic-driven transmission projects found to be needed in this planning cycle.

8.3 Reliance on Preferred Resources

The ISO has relied on a range of preferred resources in past transmission plans as well as in this 2022-2023 Transmission Plan. In some areas, such as the LA Basin, this reliance has been overt through the testing of various resource portfolios being considered for procurement, and in other areas through reliance on demand-side resources such as additional achievable energy efficiency and other existing or forecast preferred resources.

As set out in the 2022-2023 Transmission Planning Process Unified Planning Assumptions and Study Plan, the ISO assesses the potential for existing and planned demand-side resources to meet identified needs as a first step in considering mitigations to address reliability concerns.

The bulk of the ISO's additional and more focused efforts consisted of the development of local capacity requirement-need profiles for all areas and sub-areas, as part of the biennial 10-year local capacity technical study completed in this transmission planning cycle. This provides the necessary information to consider the potential to replace local capacity requirements for gas-fired generation, depending on the policy or long-term resource planning direction set by the CPUC's integrated resource planning process.

Additionally, the ISO considered numerous storage projects included in the base and sensitivity resource portfolios provided by the CPUC as mitigation for alleviating transmission constraints as set out in Chapters 2, 3, and 4 of this plan.

In addition to relying on the preferred resources incorporated into the managed forecasts prepared by the CEC, the ISO is also relying on preferred resources as part of integrated, multi-faceted solutions to address reliability needs in a number of study areas.

LA Basin-San Diego

Considerable amounts of grid-connected and behind-the-meter preferred resources in the LA Basin and San Diego local capacity area, as described in Appendix B Sections B.5.4.8 and B.6.9, were relied upon to meet the reliability needs of this large metropolitan area. Various initiatives including the LTPP local capacity long-term procurement that was approved by the CPUC have contributed to the expected development of these resources. Existing demand response was also assumed to be available within the SCE and SDG&E areas with the necessary operational characteristics (i.e., 20-minute response) for use during overlapping contingency conditions.

Oakland Sub-area

The reliability planning for the Oakland 115 kV system anticipating the retirement of local generation is advancing mitigations that include in-station transmission upgrades, an in-front-of-the-meter energy storage project and load-modifying preferred resources. These resources are being pursued through the PG&E "Oakland Clean Energy Initiative" approved in the 2017-2018 Transmission Plan. Based on the development in the procurement activities, the location of the entire 36 MW and 173 MWh storage need has been moved to Oakland C substation in the 2021-2022 TPP. This continues to satisfy the local area need in absence of the local thermal generation. The approved project is expected to be in-service in 2024.

Central Coast & Los Padres Area

To provide a sufficient maintenance window within winter months for facilities in the area as required by the ISO planning standards, in the 2020-2021 transmission planning process, the ISO recommended the mitigation plan for procurement of approximately 50 MW 4-hour BESS at Mesa 115 kV substation to address the maintenance requirements and for the North of Mesa upgrade project to remain on hold pending procurement of the battery storage. In this cycle, due to the complications associated with the 115 kV interconnection, which will result in high interconnection costs and commercial interest, the scope of the previously recommended procurement solution is recommended to be changed by moving the POI for the BESS to 230 kV and installing a new spare 230/115 kV transformer at Mesa substation.

Moorpark and Santa Clara Sub-areas

The ISO is supporting SCE's preferred resource procurement effort for the Santa Clara sub-area submitted to the CPUC Energy Division on December 21, 2017, by providing input into SCE's procurement activities and validating the effectiveness of potential portfolios identified by SCE. This procurement, together with the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double-circuit towers which was approved in the ISO's 2017-2018 Transmission Plan and went into service January 2022, will enable the retirement of the Mandalay Generating Station and the Ormond Beach Generating Station in compliance with state policy regarding the use of coastal and estuary water for once-through cooling. As set out in Appendix B Section B.5.4.8, there is 10,944 MW of energy storage in the 2032 base portfolio that was modeled in the SCE main system which includes the Moorpark and Santa Clara Sub-areas.

8.4 Competitive Solicitation for New Transmission Elements

Phase 3 of the ISO's transmission planning process includes a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities. Where the ISO selects a regional transmission solution to meet an identified need in one of the three categories, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner if that solution constitutes an upgrade to or addition on an existing participating transmission owner facility, the construction or ownership of facilities on a participating transmission owner's right-of-way, or the construction or ownership of facilities within an existing participating transmission owner's substation.

The ISO has identified the following regional transmission solutions recommended for approval in this 2022-2023 Transmission Plan as including transmission facilities that are eligible for competitive solicitation:

- Imperial Valley–North of SONGS 500 kV Line and Substation;
- North of SONGS–Serrano 500 kV line;
- North Gila–Imperial Valley 500 kV line; and

The descriptions and functional specifications for the facilities eligible for competitive solicitation can be found in Appendix G.

8.5 Capital Program Impacts on Transmission High-Voltage Access Charge

8.5.1 Background

The purpose of the ISO's internal High-Voltage Transmission Access Charge (HV TAC) estimating tool is to provide an estimation of the impact of the capital projects identified in the ISO's annual transmission planning processes on the access charge. The ISO is continuing to update and enhance its model since the tool was first used in developing results documented in the 2012-2013 transmission plan, and the model itself was released to stakeholders for review and comment in November 2018. Additional upgrades to the model have been made reflecting some of the stakeholder comments. The ISO recognizes and appreciates concerns regarding the ratepayer impacts of capital projects identified and approved in the ISO's planning process. As the ISO did in this planning cycle, it will continue to explore with stakeholders cost-effective solutions to meeting long-term needs in future planning cycles.

The final and actual determination of the High-Voltage Transmission Access Charge is the result of numerous and extremely complex revenue requirement and cost allocation exercises conducted by the ISO's participating transmission owners, with the costs being subject to FERC regulatory approval before being factored in the determination of a specific HV TAC rate recovered by the ISO from ISO customers. In seeking to provide estimates of the impacts on future access rates, we recognized it was neither helpful nor efficient to attempt to duplicate that modeling in all its detail. Rather, an excessive layer of complexity in the model would make a high-level understanding of the relative impacts of different cost drivers more difficult to review and understand. However, the cost components need to be considered in sufficient detail so the relative impacts of different decisions can be reasonably estimated.

The tool is based on the fundamental cost-of-service models employed by participating transmission owners, with a level of detail necessary to adequately estimate the impacts of changes in capital spending, operating costs, and other financial factors or considerations. Cost calculations included estimates associated with existing rate base and operating expenses, and, for new capital costs, tax, return, depreciation, and an operations and maintenance (O&M) component.

The model is not a detailed calculation of any individual participating transmission owner's revenue requirement – parties interested in that information should contact the specific participating transmission owner directly. For example, certain PTOs' existing rate bases were slightly adjusted to "true up" with a single rate of return and tax treatment to the actual initial revenue requirement incorporated into the TAC rate, recognizing that individual capital facilities are not subject to the identical return and tax treatment. This "true up" also accounts for construction funds already spent which the utility has received FERC approval to earn return and interest expense upon prior to the subject facilities being completed.

The tool does not attempt to break out rate impacts by category, e.g. reliability-driven, policy-driven and economic-driven categories used by the ISO to develop the comprehensive plan in its structured analysis, or by utility. The ISO is concerned that a breakout by ISO tariff category can create industry confusion, as, for example, a "policy-driven" project may have also addressed the need met by a previously identified reliability-driven project that was subsequently replaced by the broader policy-driven project. While the categorization is appropriate as a “policy-driven” project for transmission planning tariff purposes, it can lead to misunderstandings of the cost implications of achieving certain policies – as the entire replacement project is attributed to “policy.” Further, certain high-level cost assumptions are appropriate on an ISO-wide basis, but not necessarily appropriate to apply to any one specific utility.

8.5.2 Input Assumptions and Analysis

The ISO’s rate-impact model is based on publicly available information or ISO assumptions as set out below, with clarifications provided by several utilities.

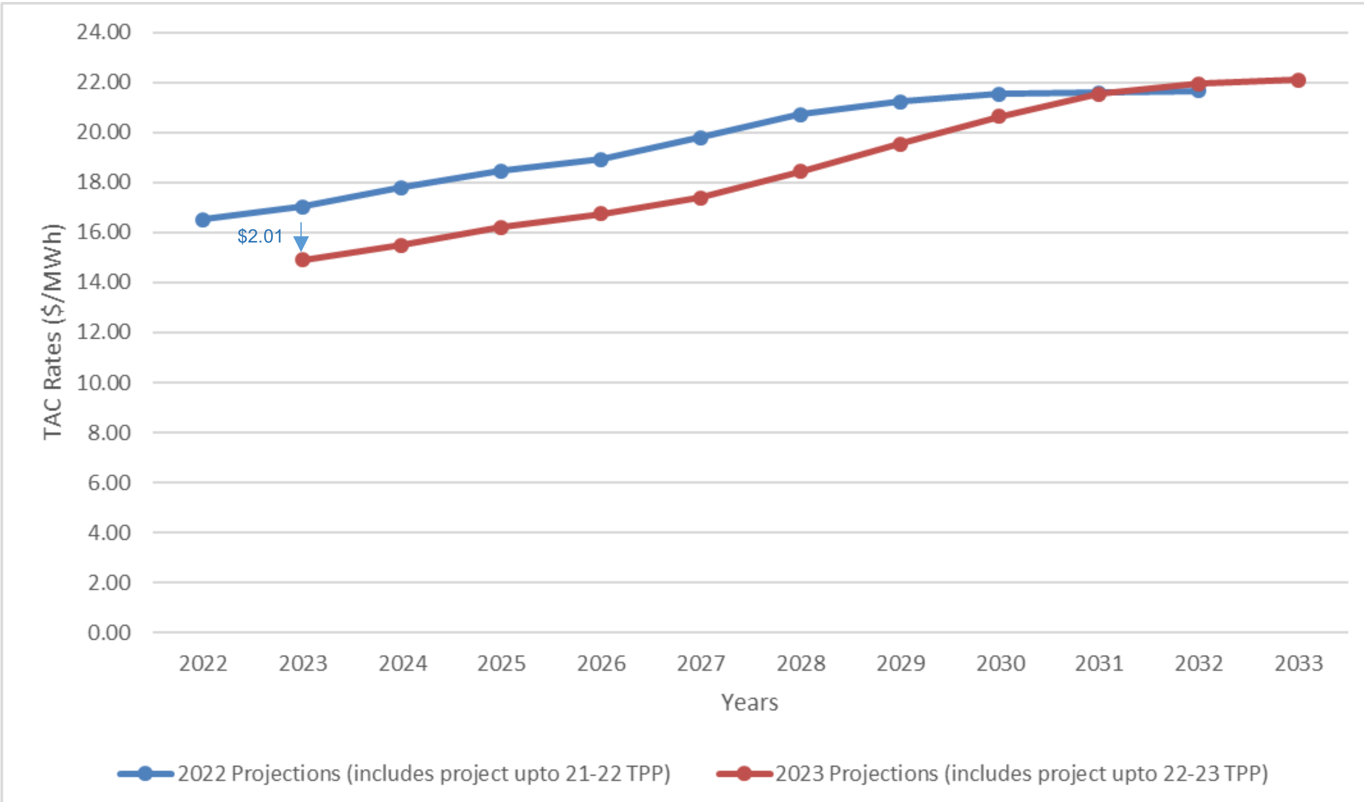
Each PTO’s most recent FERC revenue requirement approvals are relied upon for revenue requirement consisting of capital-related costs and operating expense requirements, as well as plant and depreciation balances. Single tax and financing structures for each PTO are utilized, which necessitates some adjustments to rate base. These adjustments are “back-calculated” such that each PTO’s total revenue requirement aligned with the filing.

Total existing costs are then adjusted on a going-forward basis through escalation of O&M costs, adjustments for capital maintenance costs, and depreciation impacts. PTO input is sought each year regarding these values, recognizing that the ISO does not have a role regarding those costs. The 2023 model uses the average annual 1% energy growth rate based on the CEC 2021 IPER 2021-2035 California Energy Demand baseline forecast, which is also used in the 2022-2023 TPP.

To account for the impact of ISO-approved transmission capital projects, the tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

In reviewing the latest estimate, as illustrated in Figure 8.5 1, the trend of the 2023 TAC value for the 2023 projection remains relatively consistent with the 2022 projection. The projection also includes capital projects in this year’s plan and all other transmission plan projects not already energized. The decrease of $2.01 from last year’s projection for January 1, 2023 to this year’s actuals reflects the decrease in Transmission Revenue Balancing Account Adjustments (TRBAA) and Standby Credit contribution below the historical projections. Together with a higher Gross Load growth, the lower starting values in this year's model result in lower overall TAC Rates across all years. The higher Growth Load growth rate also reduces the impact of the TAC Rates due to the recommended projects in this year's plan.

Figure 8.5-1 Forecast of ISO High Voltage Transmission Access Charge Trending from First Year of Transmission Plan



FINAL
Approved: July 20, 2023

GENERAL SESSION MINUTES
ISO BOARD OF GOVERNORS MEETING
May 18, 2023
Teleconference

May 18, 2023

The ISO Board of Governors convened the general session meeting at approximately 2:00 p.m. and the presence of a quorum was established.

ATTENDANCE

The following members of the ISO Board of Governors were in attendance:

Mary Leslie, Chair
Jan Schori, Vice Chair
Severin Borenstein
Joseph Eto
Angelina Galiteva

GENERAL SESSION

Chair Leslie provided opening remarks and welcomed Governor Joseph Eto as the newly appointed member of the ISO Board of Governors. The following agenda items were discussed in general session:

PUBLIC COMMENT

No public comment was offered at this time.

DECISION ON THE GENERAL SESSION MINUTES

Vice Chair Schori moved for approval of the ISO Board of Governors general session minutes for the March 23, 2023, meeting. The motion was seconded by Governor Galiteva and approved 4-0, with Governor Eto abstaining.

CEO REPORT

Elliot Mainzer - President and CEO, provided updates on the following topics in his CEO report: Summer readiness efforts; extended day-ahead market tariff development process; approved day-ahead market enhancements; the resource sufficiency evaluation enhancements phase 2 initiative; the 2022-2023 Transmission Plan; interconnection process reforms; and Assembly Bill 538. Mr. Mainzer concluded his report by recognizing the successful onboarding of three new WEIM participants - Avangrid Renewables, El Paso Electric, and Western Area Power Administration (WAPA) Desert Southwest.

WEIM GOVERNING BODY CHAIR REPORT

Robert Kondziolka – Chair of the WEIM Governing Body, provided highlights of the following topics discussed during the May 16, 2023, WEIM Governing Body general session meeting: ISO's CEO report to the WEIM Governing Body; activity updates from the Chairs of the Body of State Regulators and the Regional Issues Forum; and an opinion briefing from the Governing Body market expert on the day-ahead market initiative. Chair Kondziolka concluded his update by also acknowledging the three new WEIM participants - Avangrid Renewables, El Paso Electric, and Western Area Power Administration (WAPA) Desert Southwest.

DECISION ON ISO 2022-2023 TRANSMISSION PLAN

Roger Collanton, Vice President, General Counsel and Chief Compliance Officer, noted the public comment letter received from Northern California Power Agency.

Jeff Billinton – Director, Transmission Infrastructure Planning, presented Management's proposal on the 2022-2023 Transmission Plan starting with the focus of the plan. Mr. Billinton discussed the acceleration of new resource requirements to meet the state's clean energy goals combined with the rapidly escalating load growth and resource needs associated with these climate change goals, which have led to increased capital costs.

Mr. Billinton noted that this year's plan sets the foundation for a zonal approach for resource development to be able to address the rapidly escalating need for new resources. He then provided an overview of the studies and list of recommended reliability- and economic-driven projects. Next, Mr. Billinton highlighted the potential for additional recommendations for transmission projects later in the planning cycle and also noted the status of the interregional transmission projects that were submitted. Mr. Billinton concluded with an overview of stakeholder comments that were received on the plan and summarized Management's recommendations for Board approval of the plan. Discussion ensued.

Public Comment

The following provided comments on the proposal:

- Ed Smeloff on behalf of GridLab
- Cathleen Colbert on behalf of Vistra Corp
- Susan Schneider on behalf of Large-Scale Solar Association
- Mark Wyspianski on behalf of Pacific Gas & Electric
- Vishal Patel on behalf of Southern California Edison

Motion:

Vice Chair Schori:

Moved, that the ISO Board of Governors approves the ISO 2022-2023 transmission plan attached to the memorandum dated May 10, 2023.

The motion was seconded by Governor Eto and approved 5-0.

DECISION ON INTERCONNECTION PROCESS ENHANCEMENTS 2023 TRACK 1

Roger Collanton, Vice President, General Counsel and Chief Compliance Officer, noted the public comment letter received from Northern California Power Agency.

Bob Emmert – Senior Manager, Interconnection Resources, presented Management's proposal for the interconnection process enhancements 2023 track 1 initiative. Mr. Emmert started with an overview of the initial tariff revisions needed for broader transformative changes, which will be addressed in the second track of this initiative. Mr. Emmert described the purpose of the interconnection process initiative and its correlation with the CPUC and CEC processes. Mr. Emmert concluded by highlighting the increased number of interconnection requests and the proposed track 1 process changes that are intended to help manage those requests. Discussion ensued.

Public Comment

The following provided comments on the proposal:

- Ed Smeloff on behalf of GridLab
- Igor Grinberg on behalf of Pacific Gas & Electric

Motion:

Governor Galiteva:

Moved, that the ISO Board of Governors approves the proposed track 1 interconnection process enhancements, as described in the memorandum dated May 10, 2023; and

Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposal, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate **Commission guidance in any initial ruling on the proposed tariff amendment.**

The motion was seconded by Governor Borenstein and approved 5-0.

BRIEFING ON SUMMER LOADS AND RESOURCES ASSESSMENT

Neil Millar – Vice President, Infrastructure and Operations Planning, provided a briefing on the 2023 Summer Loads and Resources Assessment. Mr. Millar first noted the growth in new resources and increased hydro availability, which are expected to help offset the slight increase in load forecasted by the CEC. Mr. Millar stated that the ISO balancing authority area anticipates achieving its reliability planning target and that the peak load analysis shows significant improvement in meeting operating reserves at peak compared to last summer.

Next, Amber Motely – Sr. Manager, Short-Term Forecasting, presented diagrams that showed the snow pack conditions and temperature forecasts from June – October 2023.

Mr. Millar concluded the briefing by noting the key observations of the assessment and noted that overall conditions have significantly improved as compared to last summer. Discussion ensued.

Public Comment

There was no public comment offered at this time.

DECISION ON COMMITTEE MEMBERSHIPS

Roger Collanton – Vice President, General Counsel, Chief Compliance Officer and Corporate Secretary, introduced the topic and then the Board and Governor Eto discussed which Committee he would prefer to serve on for the next year. Mr. Eto requested to serve as a member of the Audit Committee.

Public Comment

There was no public comment offered at this time.

Motion:

Governor Galiteva:

> ***Moved, that the ISO Board of Governors elects Joe Eto, to serve as a member of the Audit Committee effective May 18, 2023 which will now consist of Joe Eto, Mary Leslie and Angelina Galiteva (Chair).***

The motion was seconded by Governor Borenstein and approved 5-0.

INFORMATIONAL REPORTS

There were no comments on the informational reports.

FUTURE AGENDA ITEMS

There were no future agenda items.

ADJOURNED

There being no additional general session matters to discuss, the general session was adjourned at approximately 3:30 p.m.

EXHIBIT 2

CAISO DESCRIPTION AND FUNCTIONAL SPECIFICATIONS FOR THE NORTH GILA-IMPERIAL VALLEY #2 500 KV LINE PROJECT (AUGUST 21, 2023)

APPENDIX I: Description and Functional Specifications for Transmission Facilities Eligible for Competitive Solicitation

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Overview

The ISO has recommended the following policy-driven projects for approval that are eligible for competitive solicitiation:

- Imperial Valley – North of SONGS 500 kV Line and Substation;
- North of SONGS – Serrano 500 kV Line;
- North Gila – Imperial Valley 500 kV Transmission Line; and

The Imperial Valley – North of SONGS 500 kV Line and Substation, North of SONGS – Serrano 500 kV Line, and North Gila – Imperial Valley 500 kV Transmission Line are part of the Southern Area Reinforcement projects to address the Devers-Red Bluff 500 kV, East of Miguel, Bay Boulevard-Silvergate, Encina-San Luis Rey, Sycamore area, San Luis Rey-San Onofre, and Silvergate-Old Town constraints.

More information on these projects are provided in Chapter 3 and Appendix F.

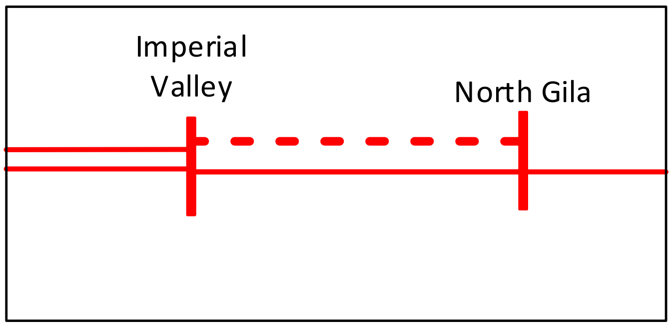
The following sections contain detailed descriptions and functional specifications for these three projects.

I.3 Description and Functional Specifications of Proposed Policy-Driven North Gila – Imperial Valley #2 500 kV Line Project

I3.1 Description

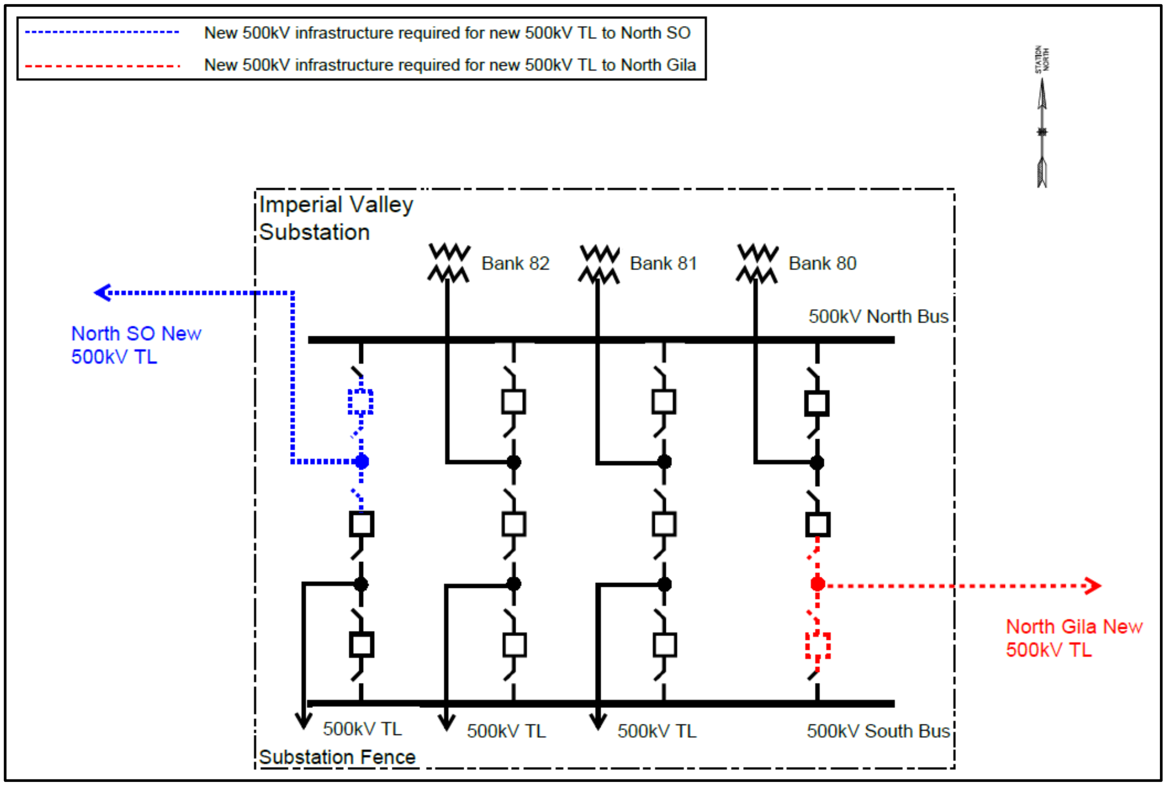
In the 2022-2023 Transmission Plan, the ISO has identified a policy-driven need for the North Gila – Imperial Valley #2 500 kV Line Project as part of the Southern Area Reinforcement Projects. Figure I.3-1 provides a schematic diagram of the transmission system in the area. As shown in the figure, the project scope includes a new 500 kV circuit between North Gila and Imperial Valley substations, estimated at 85 miles.

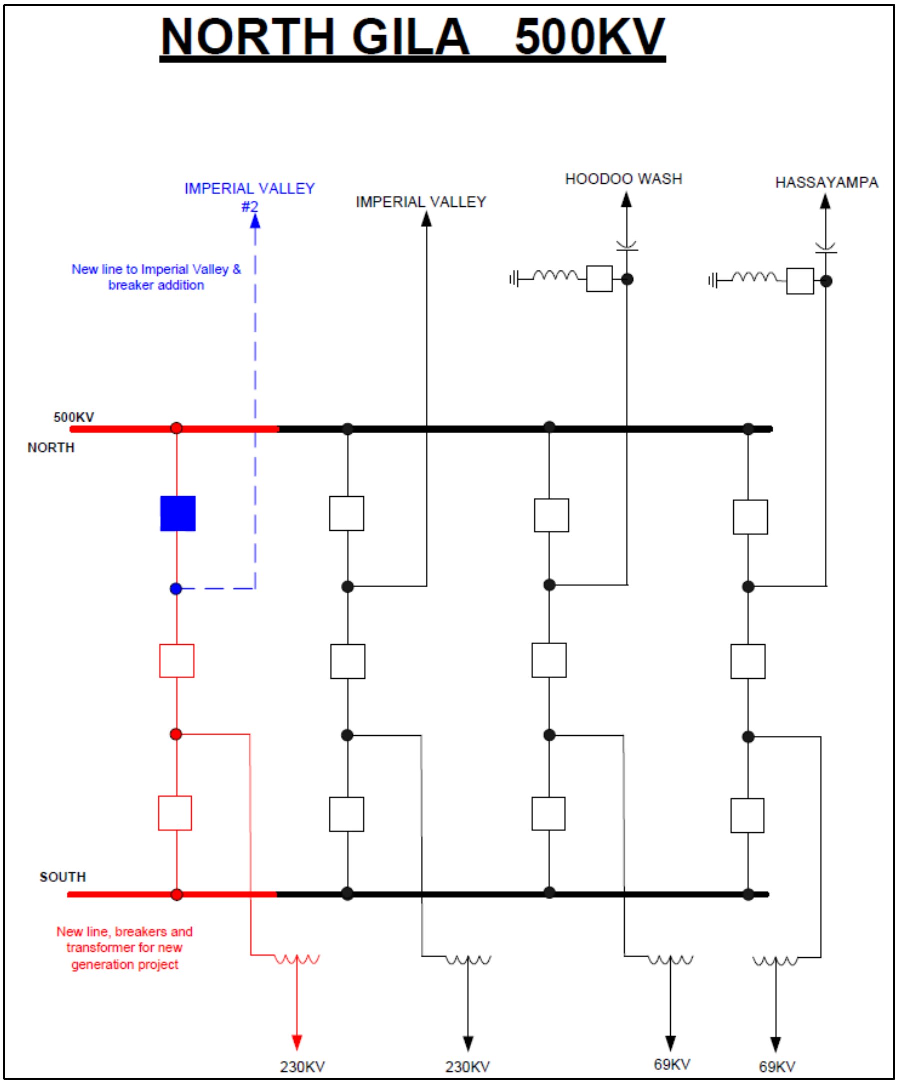
Figure I.3-1: Location of North Gila – Imperial Valley #2 500 kV Line Project



The ISO estimates that the proposed project, including both the competitive and directly assigned components, will approximately cost $340 million. The requested in-service date for the project is June 1st 2028. Figure I.3-2 provides a schematic diagram of the interconnection to North Gila and Imperial Valley 500 kV substations.

Figure I.3-2: Interconnection to North Gila 500 kV and Imperial Valley 500 kV





The facilities in the North Gila – Imperial Valley #2 500 kV Line project that are eligible for competitive solicitation is the new 500 kV line from North Gilla to Imperial Valley substation.

For the interconnection of the North Gila – Imperial Valley #2 500 kV Line to the Imperial Valley substation, the incumbent PTO (SDG&E) will be responsible for installing the new transmission line segments from the Imperial Valley 500 kV bus up to a point within 100 feet of the Imperial Valley substation property line. This new line segments will terminate on a dead end structure(s), to be owned by the incombant PTO (SDG&E). The approved project sponsor will be responsible for (and will own and maintain) the facilities from this last dead end structure(s) back to the North Gila Substation.

For the interconnection of the North Gila – Imperial Valley #2 500 kV Line to the Imperial Valley substation, the incumbent PTO (SDG&E) will be responsible for installing the new transmission line segments from the Imperial Valley 500 kV bus up to a point within 100 feet of the Imperial Valley substation property line and line shunt reactors. This new line segments will terminate on a dead end structure(s), to be owned by the incombant PTO (SDG&E). The approved project sponsor will be responsible for (and will own and maintain) the facilities from this last dead end structure(s) back to the North Gila Substation.

For the interconnection of the North Gila – Imperial Valley #2 500 kV Line to the North Gila substation, APS[1] will be responsible for installing the new transmission line segments from the North GIla 500 kV bus up to a point within 100 feet of the North Gila substation property line and line shunt reactors. This new line segments will terminate on a dead end structure(s), to be owned by the incombant PTO (SDG&E). The approved project sponsor will be responsible for (and will own and maintain) the facilities from this last dead end structure(s) back to the Imperial Valley substation.

The approved project sponsor will coordinate with SDG&E and APS for the specifications and the details of the associated line protection (e.g. current differential, directional comparison) etc. to develop relay logic and detailed relay settings.

As the project includes building new transmission facility with voltage level over 200 kV, the approved project sponsor will be responsible for completing the WECC Progress Report and other processes required for this project.

[1] APS is the entity responsible for planning, designing, constructing and maintaining the North Gila substation per the Arizona Transmission System Participation Agreement (ATSPA)

I3.2 Functional Specification for North Gila – Imperial Valley #2 500 kV Line Project

500 kV Transmission Line Functional Specifications

Overhead Line Construction

Line Terminus 1: North Gila Substation 500 kV Bus

Line Terminus 2: Imperial Valley Substation 500 kV Bus

Nominal Phase to Phase Voltage: 525 kV

Minimum Line Continuous Ampacity - Summer: 2857 Amps

Minimum Line Continuous Ampacity – Winter: 2857 Amps

Minimum Line 4 Hour Emergency Ampacity – Summer: 2857 Amps

Minimum Line 4 Hour Emergency Ampacity – Winter: 2857 Amps

Approximate Line Impedance: 0.000893 + 0.024480 pu (100 MVA base), plus 5 percent/minus 20 percent.

Approximate Line Length: 85 miles

Requested In Service Date: June 1, 2032

Support Structures: Single circuit structure

Shield Wire Required: Optical ground wire (minimum 24 pairs of fibers)

Failure Containment Loading Mitigation (anti-cascade structures, etc.): Per applicable codes

Shield Wire Ground Fault Withstand Ampacity: Coordinate with interconnecting entities

Aeolian Vibration Control (Conductor and Shield Wire): Vibration dampers must be installed on all conductors and overhead shield wires, with the exception of slack spans.

Transmission Line Minimum BIL: 1800 kV with solidly grounded systems

Minimum ROW Width: Per applicable codes

Governing Design and Construction Standards: (GO 95, NESC Code, applicable municipal codes)

Design Temperature: 50°C

EXHIBIT 3

CAISO NORTH GILA-IMPERIAL VALLEY #2 500 KV LINE PROJECT, PROJECT SPONSOR SELECTION REPORT (APRIL 11, 2024)

North Gila-Imperial Valley #2 500 kV Line Project
Project Sponsor Selection Report

April 11, 2024

California Independent System Operator Corporation

TABLE OF CONTENTS

LIST OF ATTACHMENTS

1. INTRODUCTION

This report describes the competitive solicitation process conducted by the California Independent System Operator Corporation (ISO) for the North Gila-Imperial Valley #2 500 kV Line project. The ISO conducted this competitive solicitation because, in its 2022-2023 transmission planning process, the ISO identified a policy-driven need for this transmission project. As required by the ISO Tariff, the ISO undertook a comparative analysis to determine the degree to which each project sponsor and its proposal met the qualification criteria set forth in ISO Tariff Section 24.5.3.1 and the selection factors set forth in ISO Tariff Section 24.5.4 to determine the approved project sponsor to finance, construct, own, operate, and maintain the new North Gila-Imperial Valley #2 500 kV Line project. The six qualified proposals that the ISO reviewed from the five project sponsors for the North Gila-Imperial Valley #2 500 kV Line project were detailed and well supported. The ISO emphasizes that it considers all project sponsors to be qualified to finance, construct, own, operate, and maintain the North Gila-Imperial Valley #2 500 kV Line project. While conducting the comparative analysis, the ISO had to make detailed distinctions among the project sponsors' proposals in determining the approved project sponsor. The result of this competitive solicitation process is that the ISO has selected Horizon West Transmission, LLC, as the approved project sponsor to finance, construct, own, operate, and maintain the North Gila-Imperial Valley #2 500 kV Line project.

2 BACKGROUND

2.1 North Gila-Imperial Valley #2 500 kV Line Project and Competitive Solicitation Process

The ISO Tariff specifies that the ISO's transmission planning process must include a competitive solicitation process for new, stand-alone regional transmission facilities needed for reliability, economic, and/or public policy driven reasons. The ISO's 2022-2023 transmission plan identified a policy-driven need for the North Gila-Imperial Valley #2 500 kV Line project as part of the Southern Area Reinforcement Projects to address the Devers-Red Bluff 500 kV, East of Miguel, Bay Boulevard-Silvergate, Encina-San Luis Rey, Sycamore area, San Luis Rey-San Onofre, and Silvergate-Old Town constraints. The ISO governing board approved the North Gila-Imperial Valley #2 500 kV Line project on May 18, 2023.

Following approval of the transmission plan, the ISO opened a bid solicitation window on June 26, 2023, which provided project sponsors the opportunity to submit proposals to finance, construct, own, operate, and maintain the North Gila-Imperial Valley #2 500 kV Line. Project sponsors had an opportunity to express interest in collaborating with another entity during the first ten business days after the bid window opened. No project sponsor requested collaboration. In accordance with ISO Tariff Section 24.5.1 and the posted 2022-2023 Transmission Planning Process Phase 3 Sequence Schedule, the bid solicitation window remained open through September 29, 2023.

The ISO Functional Specifications for this project are located in Appendix I of the 2022-2023 transmission plan, under the title *Description and Functional Specifications of Proposed Policy-Driven North Gila-Imperial Valley #2 500 kV Line Project* (ISO Functional Specifications), as updated as of August 21, 2023.[1] In the ISO Functional Specifications, the North Gila-Imperial Valley #2 500 kV Line project is described as follows:

- A new 500 kV circuit between North Gila and Imperial Valley substations, estimated at 85 miles.

In the ISO Functional Specifications, the ISO provided estimates of costs for the entire project, but it did not break out the costs of the work between San Diego Gas & Electric (SDG&E), Arizona Public Service Company (APS), and the approved project sponsor. As stated in the ISO Functional Specifications, the ISO estimates the overall proposed project (both the part subject to competitive solicitation and the part not subject to competitive solicitation) will cost approximately $340 million. The ISO also specified that the project must be in service no later than June 1, 2032, as clarified in the question and answer matrix posted on the ISO website. Upon completion of the project, the approved project sponsor will own the new North Gila-Imperial Valley #2 500 kV transmission line, but it must turn the facilities over to ISO operational control.

[1] ISO Functional Specifications
https://www.caiso.com/Documents/Appendix-I-Board-Approved-2022-2023-Transmission-Plan-AdditionalRevisions.pdf

The ISO also identified and on July 7, 2023, posted the revised list of key selection factors for the North Gila-Imperial Valley #2 500 kV Line project.[2] After the ISO opened the bid solicitation window, the ISO hosted an informational call for interested parties on June 26, 2023, and provided a presentation describing the project and the competitive solicitation process, including the key selection factors.[3] These are the tariff criteria the ISO determined are the most important for selecting a project sponsor for this policy driven project. For purposes of this report, the ISO identified the following subsections of ISO Tariff 24.5.4 as the key selection factors:

- Section 24.5.4 (b) – "the Project Sponsor's existing rights of way and substations that would contribute to the transmission solution in question;"

- Section 24.5.4 (c) – "the experience of the Project Sponsor and its team in acquiring rights of way, if necessary, that would facilitate approval and construction, and in the case of a Project Sponsor with existing rights of way, whether the Project Sponsor would incur costs in connection with placing new or additional facilities associated with the transmission solution on such existing right of way;"

- Section 24.5.4 (d) – "the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet the schedule of the Project Sponsor and its team;"

- Section 24.5.4 (e) – "the financial resources of the Project Sponsor and its team;"

- Section 24.5.4 (f) – "the technical and engineering qualifications and experience of the Project Sponsor and its team;"

- Section 24.5.4 (j) – "demonstrated cost containment capability of the Project Sponsor and its team, specifically, binding cost control measures the Project Sponsor agrees to accept, including any binding agreements by the Project Sponsor and its team to accept a cost cap that would preclude costs for the transmission solution above the cap from being recovered through the CAISO's Transmission Access Charge, and, if none of the competing Project Sponsors proposes a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the Project Sponsor, and its history of imposing such measures."

The ISO evaluated six proposals from five project sponsors – (1) California Grid Holdings LLC (CalGrid), a wholly owned subsidiary of Viridon Holdings LLC, (2) Horizon West Transmission, LLC (Horizon West), a wholly-owned subsidiary of NextEra Energy Transmission, LLC (NEET), (3) Lotus Infrastructure Global Operations, LLC (Lotus), (4) LS Power Grid California, LLC (LSPGC), a wholly-owned subsidiary of LS Power Associates, L.P., and (5) Valley Power Connect, LLC (VPC), a Delaware limited liability

[2] Key Selection Factors
http://www.caiso.com/InitiativeDocuments/Key-Selection-Factors-2022-2023-Transmission-Planning-Process.pdf

[3] Phase 3 TPP Presentation
http://www.caiso.com/InitiativeDocuments/Presentation-2022%E2%80%932023-Transmission-Planning-Process-Phase-3-Competitive-Solicitation-Jun262023.pdf

company and wholly owned subsidiary of Grid United, a Delaware limited liability company, in association with Citizens Energy Corporation (Citizens Energy) and Imperial Irrigation District (IID). The ISO posted a list of validated project sponsor applications on November 20, 2023.[4] The ISO found that all six of the proposals provided sufficient information to meet the minimum validation criteria as set forth in Section 24.5.2.4 of the ISO Tariff. The ISO posted a list of qualified project sponsors and proposals on January 11, 2024.[5] The ISO found that all five project sponsors and their six validated proposals met the minimum qualification criteria as set forth in Section 24.5.3 of the ISO Tariff.

2.2 The ISO Transmission Planning Process and Competitive Solicitation Tariff Structure

In 2010, the Federal Energy Regulatory Commission (FERC) approved changes to the ISO's transmission planning process that included a competitive solicitation process for new, stand-alone transmission facilities needed for reliability, economic, and/or public policy driven reasons. Subsequently, in 2012 the ISO filed tariff amendments to comply with the requirements of FERC Order No. 1000 to further promote competition in the transmission planning process. The ISO conducted its first competitive solicitation process during the 2012-2013 transmission planning cycle. Based on the experience gained during the competitive selection process and discussions with stakeholders, the ISO identified improvements to clarify and provide more transparency to the process for participating transmission owners (PTOs) and other transmission developers. The ISO conducted a competitive transmission improvement initiative in late 2013, which concluded with ISO Tariff Section 24.5 and process changes.

The framework for the 2022-2023 transmission plan competitive solicitation process is set forth in ISO Tariff Section 24.5. In addition, the ISO posted the form of the project sponsor application (Attachment 1) on its website. Also, while the bid solicitation window was open, the ISO maintained and posted on its website a question-and-answer matrix detailing questions from prospective project sponsors and the ISO's responses thereto so that all interested parties would have access to the same clarifying information.[6] In compliance with ISO Tariff Section 24.5.3.5, the ISO engaged two well-respected, international industry consulting firms to assist the ISO in its selection of the approved project sponsor. One firm primarily supports the ISO in the qualification and comparative analysis associated with the project schedule, rights-of-way acquisition, environmental permitting, design, construction, maintenance, and operating capabilities of the project sponsors. The other firm provides economic, financial, and rate expertise and provides cost of service analyses. Both firms have committed to remain unbiased and not participate with any project sponsor in the competitive solicitation process.

Each project sponsor completed the project application form, which included a series of questions and requirements in the following areas:

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[4] Validated Project Sponsor Applications
http://www.caiso.com/InitiativeDocuments/List-of-Validated-Project-Sponsor-Applications-North-Gila-to-Imperial-Valley-2-500kV-Transmission-Line-Project.pdf

[5] Qualified Project Sponsor Applications
http://www.caiso.com/InitiativeDocuments/List-of-Qualified-Project-Sponsor-Applications-North-Gila-to-Imperial-Valley-2-500kV-Transmission-Line-Project.pdf

[6] Response to Comments Matrix
http://www.caiso.com/InitiativeDocuments/ISO-Responses-to-Comments-Matrix-2022-2023-Transmission-Planning-Process-Competitive-Solicitation.pdf

- Project Sponsor, Name, Organizational Structure, and Proposal Summary
- Project Qualifications
- Prior Projects and Experience
- Project Management and Schedule
- Cost Containment
- Financial
- Environment Permitting and Public Process
- Transmission or Substation Land Acquisition
- Substation Design and Engineering
- Transmission Line Design and Engineering
- Construction
- Maintenance
- Operations
- Miscellaneous
- Officer Certification
- Application Deposit Payment Instructions

The ISO provided the project sponsors opportunities to correct deficiencies in their applications. Following a project sponsor's submission of supplemental information, the ISO validated the project sponsor's application to determine if it contained sufficient information for the ISO to determine whether the project sponsor and its proposal were qualified. Once the ISO validated the applications, the ISO posted the list of validated project sponsor applications to its website on November 20, 2023, as described in Section 2.1 of this report. As also described in Section 2.1, the ISO validated all six of the applications.

Next, the ISO determined whether the project sponsors and their proposals were qualified pursuant to ISO Tariff Sections 24.5.3.1 and 24.5.3.2. The ISO evaluated the project sponsors based on the information submitted in response to the questions in the application corresponding to ISO Tariff Sections 24.5.2.1(a)-(i) to determine, in accordance with Section 24.5.3.1, whether the project sponsor had demonstrated that its team is physically, technically, and financially capable of:

(i) completing the needed transmission solution in a timely and competent manner; and
(ii) operating and maintaining the transmission solution in a manner that is consistent with good utility practice and applicable reliability criteria for the life of the project, based on the qualification criteria as set forth in ISO Tariff Section 24.5.3.1(a)-(f).

In accordance with Section 24.5.3.2, the ISO evaluated the project sponsors' proposals based on the following criteria to determine whether the transmission solution proposed by the project sponsors would be qualified for consideration:

(a) "Whether the proposed design of the transmission solution is consistent with needs identified in the comprehensive Transmission Plan;"
(b) "Whether the proposed design of the transmission solution satisfies Applicable Reliability Criteria and CAISO Planning Standards."

The ISO found that all five project sponsors and their six validated proposals met the minimum qualification criteria as set forth in ISO Tariff Sections 24.5.3.1 and 24.5.3.2 for the North Gila-Imperial Valley 500 kV Line project. Therefore, the ISO determined that no cure period was needed for the qualification phase. As described in Section 2.1 of this report, the ISO posted the list of qualified project sponsors and their proposals to its website on January 11, 2024. Section 3 of this report describes the ISO's selection process for this project.

3 SELECTION OF THE APPROVED PROJECT SPONSOR

3.1 Description of Project Sponsor Selection Process

Once the ISO has determined that two or more project sponsors are qualified, ISO Tariff Section 24.5.3.5 directs the ISO to select one approved project sponsor "based on a comparative analysis of the degree to which each project sponsor's proposal meets the qualification criteria set forth in section 24.5.3.1 and the selection factors set forth in 24.5.4." The selection factors specified in ISO Tariff Section 24.5.4 are:

(a) the current and expected capabilities of the Project Sponsor and its team to finance, license, and construct the facility and operate and maintain it for the life of the solution;
(b) the Project Sponsor's existing rights of way and substations that would contribute to the transmission solution in question;
(c) the experience of the Project Sponsor and its team in acquiring rights of way, if necessary, that would facilitate approval and construction, and in the case of a Project Sponsor with existing rights of way, whether the Project Sponsor would incur incremental costs in connection with placing new or additional facilities associated with the transmission solution on such existing right of way;
(d) the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet that schedule of the Project Sponsor and its team;
(e) the financial resources of the Project Sponsor and its team;
(f) The technical and engineering qualifications and experience of the Project Sponsor and its team;
(g) if applicable, the previous record regarding construction and maintenance of transmission facilities, including facilities outside the CAISO Controlled Grid of the Project Sponsor and its team;
(h) demonstrated capability to adhere to standardized construction, maintenance and operating practices of the Project Sponsor and its team;
(i) demonstrated ability to assume liability for major losses resulting from failure of facilities of the Project Sponsor;
(j) demonstrated cost containment capability of the Project Sponsor and its team, specifically, binding cost control measures the Project Sponsor agrees to accept, including any binding agreement by the Project Sponsor and its team to accept a cost cap that would preclude costs for the transmission solution above the cap from being recovered through the CAISO's Transmission Access Charge, and, if none of the competing Project Sponsors proposes a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the Project Sponsor, and its history of imposing such measures; and
(k) any other strengths and advantages the Project Sponsor and its team may have to build and own the specific transmission solution, as well as any specific efficiencies or benefits demonstrated in their proposal.

In selecting the approved project sponsor, the ISO undertook a comparative analysis of the project sponsors' proposals regarding the qualification criteria described in ISO Tariff Section 24.5.3.1 and the selection factors in ISO Tariff Section 24.5.4. As part of the comparative analysis, the ISO has given particular consideration to the key selection factors for the North Gila-Imperial Valley #2 500 kV Line project as described in Section 2.1 of this report.

This report summarizes information provided by each project sponsor that was considered by the ISO to be important in analyzing their proposals regarding each of the qualification criteria and selection factors. At the beginning of each subsection of this Section 3, commencing with Section 3.4, of this report, the ISO has provided a listing of the sections of the project sponsor's application that the ISO particularly considered in undertaking its comparative analysis for that qualification criterion or selection factor. In addition, in the ISO's summaries in this report describing the information provided by each project sponsor, the ISO has provided a reference to the particular sections of the project sponsor's application that served as the source for that summary.

In undertaking its analysis of the merits of the information provided in a project sponsor's proposal, the ISO accounted for information provided regarding the experience of a project sponsor and its team as follows. In any case where a project sponsor provided a list of potential contractors to perform one of the activities that is the subject of a selection factor, the ISO used the experience of the contractor on the list with the least experience in evaluating the experience of the project sponsor and its team. This approach accounts for the possibility that the project sponsor might ultimately choose to use that contractor. Additionally, in any case where a project sponsor is a recently-formed entity -- for purposes of this report, CalGrid, the ISO evaluated the project sponsor's prior experience based on the indicated experience of the members of its team. Finally, the ISO has concluded that there is no significant difference between the two proposals submitted by VPC with regard to many aspects of the satisfaction of the selection factors. Consequently, references to VPC and its proposal in this report apply equally to both VPC's VPC proposal and VPC's Dunes proposal unless this report includes an express distinction between the two proposals.

Because this report is a summary, it does not repeat all of the information provided by the project sponsors. However, the ISO reviewed and considered all of the information provided by the project sponsors, and the ISO's failure to reference any specific information provided by a project sponsor does not indicate lack of consideration of such information.

3.2 Description of Project Sponsors for the North Gila-Imperial Valley #2 500 kV Line Project

The ISO evaluated six validated and qualified project sponsor applications for the North Gila-Imperial Valley #2 500 kV Line project submitted by five project sponsors:

- CalGrid
- Horizon West
- Lotus
- LSPGC
- VPC, which submitted two proposals -- referred to herein as the VPC proposal and the VPC Dunes proposal

All five entities are qualified and submitted strong, competitive applications supporting their proposals. As a result, the ISO had to make detailed distinctions among the five project sponsors and their six validated and qualified proposals in the comparative analysis process in selecting the approved project sponsor.

CalGrid

According to its proposal, CalGrid is a wholly owned subsidiary of Viridon Holdings LLC, which, together with its subsidiaries and affiliates, is generally known as Viridon. CalGrid indicated that it is a Delaware limited liability company established as a holding company for greenfield transmission projects in California. CalGrid indicated Viridon is headquartered in Chicago, Illinois, and was formed in 2023 by a team of experienced transmission industry leaders, with over 25 years of combined experience in the competitive transmission business, to expedite the clean energy transition by investing in and managing electric transmission facilities across North America. CalGrid indicated Viridon is a portfolio company of Blackstone Inc. (Blackstone), which is a publicly traded company. (A-5) CalGrid indicated that Blackstone's latest investment fund, Blackstone Energy Transition Partners IV (BETP IV) is the majority owner of Viridon's equity interest and that it is relying on BETP IV and its ultimate parent, Blackstone, to provide financial support and guarantees for this project. (A-5)

CalGrid indicated that it proposes to create a special purpose entity in the form of a limited liability company to finance, construct, own, and operate this transmission asset if selected as the approved project sponsor for the project. CalGrid indicated that the special purpose entity would be a wholly-owned subsidiary of CalGrid. CalGrid indicated it would utilize Viridon personnel to perform or manage all aspects of the project. CalGrid indicated that Viridon personnel are employed by Viridon Services LLC, a service company that, through intermediate holding companies, is a wholly-owned subsidiary of Viridon Holdings LLC. CalGrid indicated that although Viridon was formed in 2023, its management team has extensive experience and a deep understanding of how to design, develop, construct, own, and operate complex transmission facilities. (A-5)

CalGrid Access to Affiliate Financial Support

CalGrid indicated the project would be financed using a combination of equity and debt. CalGrid indicated that Viridon, acting through CalGrid and with the support of majority owner BETP IV, would invest 100% of the equity required to finance the project and anticipates using debt and equity throughout the project's life. CalGrid indicated that CalGrid and the special purpose entity, as wholly owned subsidiaries of Viridon and affiliates of Viridon's majority owner BETP IV, ultimate parent Blackstone, and other Blackstone entities, would benefit from all relevant capabilities and resources of the combined Viridon and Blackstone organizations. (F-1, F-5)

CalGrid's proposal included a parent support letter from Blackstone indicating support for the project by Blackstone, the ultimate parent of the project's majority owner BETP IV, and that BETP IV would benefit from Blackstone's strong reputation in the financial community. (F2.2)

CalGrid's proposal also included pro forma financial instruments to support the equity funding requirements of the project, which would be effective conditional upon selection of CalGrid as the approved project sponsor and closing of the financing. (F-2.3, F-2.4)

Horizon West

According to its proposal, Horizon West is a Delaware limited liability company formed in 2014 that is a wholly-owned subsidiary of NextEra Energy Transmission, LLC (NEET) and an indirect subsidiary of NextEra Energy, Inc. (NextEra). Horizon West indicated that it would own this project and other assets in the ISO region as a portfolio and is not intended to be a stand-alone project company for this project. (Executive Summary, A-5, F-1)

Horizon West indicated that NextEra, its ultimate parent, and its wholly owned subsidiary NEET are headquartered in Juno Beach, Florida, and NextEra's principal subsidiaries are Florida Power & Light Company and NextEra Energy Resources, LLC. Horizon West indicated that another key entity in the NextEra organization is NextEra Energy Capital Holdings, Inc. (NEECH), which is a wholly-owned subsidiary of NextEra and owns and provides funding for NextEra's operating subsidiaries, other than Florida Power & Light Company and its subsidiaries, including NEET and Horizon West.

Horizon West indicated that its immediate parent, NEET, was formed by NextEra in 2007 to leverage NextEra's experience and resources in developing, designing, constructing, owning, and operating transmission facilities across the United States and Canada and that NEET's assets include operating transmission facilities in California (the Suncrest static voltage and reactive control (VAR) compensator (SVC) facility and Trans Bay Cable, LLC (Trans Bay Cable) high voltage direct current (HVDC) facility), Nevada, Texas, New Hampshire, Illinois and Kentucky, Kansas and Oklahoma, and Ontario (Canada). (Executive Summary, A-5)

Horizon West's Access to Affiliate Financial Support

Horizon West indicated that during development, permitting, and construction of the project it would enter into debt financing arrangements and receive equity from NextEra's financing affiliate, NEECH. Upon commercial operations and throughout the life of the project, Horizon West indicated that it plans to finance the project with debt from NEECH. (F-1)

Horizon West provided a letter from NextEra indicating that NEECH would provide appropriate funding and needed guarantees to Horizon West and that those would in turn be guaranteed by NextEra as provided for through a blanket guarantee arrangement between NEECH and NextEra. (F-2, F-2e, F-2f)

Lotus

According to its proposal, Lotus specializes in deploying equity capital in energy infrastructure investment in North America, with a focus on the transmission, renewable power generation, energy storage, biofuels, and natural gas sectors. Lotus indicated that it would create a special purpose entity as an affiliate for purposes of developing the project. Lotus indicated that the special purpose entity would be managed by Lotus through Lotus Infrastructure Fund III U.S. AIV, LP. (LIF III) and affiliated investment vehicles specifically to finance, construct, own, maintain, and operate the project. (A-5, F-5)

Lotus Access to Affiliate Financial Support

Lotus indicated that it has sufficient capital through LIF III and investment affiliates to support the construction of the project and any potential liabilities. (F-1, F-2).

Lotus provided a written parent guarantee, providing financial assurance that LIF III, as the direct parent of the special purpose entity to be formed specifically for this project, would provide customary credit support and has adequate financial resources to provide the financial support for the project repairs and permitting of the project. (F-2.1)

LSPGC

According to its proposal, LSPGC is a Delaware limited liability company established to own transmission projects in California, including this project. LSPGC indicated that, through intermediate holding companies (LS Power Grid California Holdings, LLC, LSP Transmission Holdings, LLC, and LSP Generation IV, LLC), it is a wholly-owned subsidiary of LS Power Associates, L.P., which, together with its subsidiaries and affiliates, is generally known as LS Power. LSPGC indicated that a similar ownership and organization structure has been used by LS Power for its past projects, including all of its transmission projects. (A-5)

LSPGC indicated that it would utilize LS Power personnel to perform or manage all aspects of the project. LSPGC also identified six affiliates as particularly relevant to its proposal: (i) Cross Texas Transmission, LLC (Cross Texas), a transmission service provider in Texas, (ii) DesertLink, LLC (DesertLink), the owner of the Harry Allen-Eldorado 500 kV transmission line competitively selected by the ISO in 2016, (iii) Great Basin Transmission South, LLC, owner of a 75% interest in the One Nevada Transmission Line facilities in Nevada, (iv) Republic Transmission, LLC, the owner of the Duff to Coleman 345 kV transmission line in Indiana competitively awarded by MISO in 2016, (v) Silver Run Electric, LLC, the owner of the Silver Run 230 kV Substation and Silver Run-Hope Creek 230 kV transmission line competitively awarded by PJM in 2014, and (vi) LS Power Grid New York Corporation I, the owner of the Gordon Road and Princetown 345 kV gas-insulated switchgear (GIS) substations and 345 kV transmission line in New York competitively awarded by NYISO in 2019. (A-5)

LSPGC Access to Affiliate Financial Support

LSPGC indicated that it is relying on its parent LS Power to satisfy the financial criterion for this project. LSPGC provided evidence of LS Power's financial assurances to LSPGC in the form of a written guarantee. (F-2, F-2A)

LSPGC also provided an equity financing commitment from LS Power's majority owner management company indicating the majority owner's commitment to provide funding to LS Power for the project. (F-2B)

VPC

According to its proposal, VPC is a Delaware limited liability company and wholly owned subsidiary of Grid United, LLC (Grid United), also a Delaware limited liability company. VPC indicated that Grid United is backed by its ultimate parent company Centaurus Capital LP (Centaurus). (A-5)

VPC indicated that the project company is a limited liability company that is jointly owned by VPC and Southwest Transmission Partners, LLC (STP). VPC indicated that VPC would have the option to purchase additional ownership interest in the project company from STP and that IID and Citizens Energy would participate in the project pursuant to a coordination agreement. According to VPC's proposal, STP is an Arizona limited liability company that currently owns 60% of the issued and outstanding limited liability company interests in the project company. The proposal also indicated that Citizens Energy is a Massachusetts non-profit 501(c)(4) corporation that owns Citizens Enterprises Corporation (a for-profit holding company) and IID is organized under the Water Code of the State of California. (A-5 Coordination Agreement)

VPC indicated that under the coordination agreement, IID and Citizens Energy would have the option to invest in the project in exchange for the ability to acquire leasehold interests in portions of the transmission capacity rights of the project post construction. (A-5)

VPC indicated that IID would invest in a portion of the transmission capacity associated with the project. (A-5 Coordination Agreement) VPC indicated that IID would be a non-PTO holding Transmission Ownership Rights under Article Section 17 of the ISO Tariff equal to its 20% ownership of the eastern segment of the new transmission line and for the VPC Dunes proposed project would also own 40% ownership of its new proposed Dunes 500 kV Switching Station.

VPC Access to Affiliate Financial Support

VPC indicated that funding costs incurred by the project company in the development and construction phases of the project would be provided by VPC's parent company, Grid United, which would be provided 100% project-level equity for the project from Centaurus and would also raise project-level debt. (A-5)

VPC indicated it would rely on Centaurus for the financial backing of equity for the project, which would be available to support the construction and development of the project. (F-2) VPC provided a financial commitment letter, signed by an officer, providing financial assurance that Centaurus, as the direct parent of VPC, would provide equity and has adequate financial resources to provide the financial support for the project to either VPC or Grid United for the project company. (F-2)

3.3 Selection Factor 24.5.4(a): Overall Capability to Finance, License, Construct, Operate, and Maintain the Facility

The ISO notes that the first selection factor is a broad factor that generally encompasses several subsequent narrower selection factors. The ISO will address satisfaction of this more general factor in its discussion of the applicable, more specific selection factors. The ISO will not duplicate here (1) the information provided by the project sponsors for purposes of demonstrating their capabilities and experience regarding each of the encompassed selection factors, or (2) the ISO's comparative analysis of the project sponsors' proposals in this regard, as set forth in the following sections of this report. The ISO will discuss the comparative analysis for selection factor 24.5.4(a) in Section 3.14 of this report after the discussion of the other selection factors.

3.4 Selection Factor 24.5.4(b): Existing Rights-of-Way and Substations that Would Contribute to the Project

(Executive Summary, L-1, L-4, E-1, E-2)

The second selection factor is "the Project Sponsor's existing rights of way and substations that would contribute to the transmission solution in question." As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because the availability of existing rights-of-way can contribute to lower project cost, reduced rights-of-way acquisition efforts, and reduction in the overall time needed to complete the project.

3.4.1 Information Provided by CalGrid

CalGrid indicated it does not have any existing land rights to support the project. (L-4)

CalGrid indicated it would acquire land rights from the U.S. Bureau of Land Management (BLM), Fort Yuma Quechan Tribe, U.S. Bureau of Reclamation, and private landowners. (E-2, L-1)

CalGrid indicated that additional discussions with the Fort Yuma Quechan Tribe would be required to acquire land rights. (L-1)

Furthermore, CalGrid indicated if negotiations with the Fort Yuma Quechan Tribe were to fail, it has an alternative route that avoids the tribal lands. (E-2)

3.4.2 Information Provided by Horizon West

Horizon West indicated it does not have any existing land rights to contribute to the project. (L-4)

Horizon West indicated it would acquire land rights from the BLM, U.S. Bureau of Reclamation, and private landowners. (E-2, L-1)

Horizon West indicated it avoided tribal lands with its proposed route. (L-1)

Horizon West indicated that it conducted a critical issues analysis and studied a number of alternative routes. Horizon West indicated that the proposed route would require approximately 1540 acres of federal managed land and 518 acres of private land. (L-1)

3.4.3 Information Provided by Lotus

Lotus indicated it does not have any existing land rights to contribute to the project. (L-4)

Lotus indicated it would acquire land rights from the BLM, Fort Yuma Quechan Tribe, U.S. Bureau of Reclamation, and private landowners. (E-2, L-1)

Lotus indicated that it had thoroughly evaluated the risk of securing land rights on the Fort Yuma Quechan Tribe Reservation, including routes that avoided the reservation and were studied as part of the 2019 Section 368 energy corridor regional reviews. (L-1)

Lotus indicated that it has a history of working with the Fort Yuma Quechan Tribe on its Ten Link West project and has had discussions with the Tribe concerning its preferred route. Furthermore, Lotus indicated if negotiations with the Fort Yuma Quechan Tribe were to fail it has an alternative route that avoids the tribal lands. (L-1)

3.4.4 Information Provided by LSPGC

LSPGC indicated it does not have any existing land rights to contribute to the project. (L-4)

LSPGC indicated it would acquire land rights from the BLM, U.S. Bureau of Reclamation, and private landowners. (E-2, L-1)

LSPGC indicated it had completed a comprehensive evaluation of suitable route alternatives for the project and selected a proposed route that minimizes impacts and supports a constructible design. LSPGC indicated that the proposed route avoids tribal land. (L-1)

LSPGC indicated that it completed a thorough review of opportunities, constraints, and concerns analysis, including a helicopter survey of the route alternatives. (L-1)

3.4.5 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC indicated it does not have any existing land rights to contribute to the project. (L-4)

VPC indicated it would acquire land rights from the BLM, U.S. Bureau of Reclamation, and private landowners. (E-2, L-1)

VPC provided a routing study that included a detailed analysis of all siting opportunities and constraints located within the study area for the proposed project and provided the rationale behind selection of the alternative routes analyzed and the selection of the proposed route. (L-1)

VPC indicated it filed a SF-299 form (Application for Transportation, Utility Systems, Telecommunications and Facilities on Federal Lands and Property) and cost recovery agreement with the BLM in 2009 and it has been serialized by the BLM and updated several times since, including the submission of a routing study and plan of development in 2019. (E-4)

VPC indicated that it had already submitted to the BLM a draft plan of development and 18 draft mitigation plans and has worked with the BLM to identify possible issues, study requirements, and mitigation measures. VPC indicated that this would allow the BLM's National Environmental Policy Act (NEPA) review and further action on the rights-of-way application to proceed quickly and efficiently after ISO award. (E-4)

3.4.6 ISO Comparative Analysis

For purposes of the comparative analysis for this factor, the ISO has considered the representations by the project sponsors regarding the rights-of-way or other land rights they possess and are proposing to contribute to this project and acquisition of land rights needed for the project.

All six proposals of the five project sponsors indicated that the project sponsors did not have existing land rights along the project route.

Subject to the following considerations, the ISO considers all five project sponsors to have sufficient plans for the acquisition of the necessary land rights for the project.

The ISO notes that VPC submitted an SF-299 package to the BLM originally in 2009 for a similar project and recently updated the information for this project. VPC also submitted a draft plan of development and a number of mitigation plans to the BLM. The ISO recognizes that all of the project sponsors will utilize the SF-299 process and submit a plan of development to the BLM, so the ISO does not consider this to give VPC a significant advantage regarding ability to acquire sufficient land rights for the project. However, the ISO recognizes that this could give VPC a potential advantage regarding the project schedule because it can take a year or more for this process. The ISO considers this potential advantage related to the VPC and VPC Dunes project schedule in Section 3.6.

The ISO also notes that the routing proposals of CalGrid and Lotus cross Fort Yuma Quechan Tribe lands, which has the potential of increasing project schedule risk and increasing project costs if there are any issues with securing land rights to cross the Fort Yuma Quechan Tribe lands. The ISO considers these potential schedule and cost risks in Sections 3.6 and 3.12 respectively. While the proposals to cross tribal lands would otherwise also result in risks to the ability of CalGrid and Lotus to acquire land rights for the project, the proposals of CalGrid and Lotus included alternate routes that would avoid the need to cross tribal lands. The ISO considers the inclusion of these proposed alternate routes to minimize the risks to the ability of CalGrid and Lotus to acquire sufficient land rights to develop the project.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the six proposals of the five project sponsors regarding this factor.

3.5 Selection Factor 24.5.4(c): Experience in Acquiring Rights-of-Way

The third selection factor is "the experience of the Project Sponsor and its team in acquiring rights of way, if necessary, that would facilitate approval and construction, and in the case of a Project Sponsor with existing rights of way, whether the Project Sponsor would incur incremental costs in connection with placing new or additional facilities associated with the transmission solution on such existing right of way." As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because experience in acquiring rights-of-way can contribute to lower project cost, reduced rights-of-way acquisition efforts, and reduction in the overall time needed to complete the project.

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) the experience of the project sponsor and its team in acquiring rights-of-way and (2) for the case of a project sponsor with existing rights-of-way, whether the project sponsor would incur incremental costs in connection with placing new or additional facilities associated with the transmission solution on such existing rights-of-way.

Experience in Acquiring Rights-of-Way

(Prior Projects and Experience Workbook)

3.5.1 Information Provided by CalGrid

CalGrid provided a list of its experience and the experience of its contractors with acquiring rights-of-way for transmission line projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 33 transmission line projects, with one in California. (Prior Projects and Experience Workbook)

3.5.2 Information Provided by Horizon West

Horizon West provided a list of its experience and the experience of its contractors with acquiring rights-of-way for transmission line projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 59 transmission line projects, with two in California. (Prior Projects and Experience Workbook)

3.5.3 Information Provided by Lotus

Lotus provided a list of its experience and the experience of its contractors with acquiring rights-of-way for transmission line projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included five transmission line projects, with two in California. (Prior Projects and Experience Workbook)

3.5.4 Information Provided by LSPGC

LSPGC provided a list of its experience and the experience of its contractors with acquiring rights-of-way for transmission line projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included nine transmission line projects, with none in California. (Prior Projects and Experience Workbook)

3.5.5 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC provided a list of its experience and the experience of its contractors with acquiring rights-of-way for transmission line projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included two transmission line projects, with one in California. (Prior Projects and Experience Workbook)

For the VPC Dunes proposal, VPC provided a list of its experience and the experience of its contractors with acquiring rights-of-way for substation projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided showed no projects in the U.S. (Prior Projects and Experience Workbook).

VPC indicated that IID has more permitting and land acquisition experience in the project region than any other entity and would act as the California Environmental Quality Act (CEQA) lead agency for the project. (A-4)

Incremental Costs Associated with Use of Existing Rights-of-Way

(L-4)

3.5.6 Information Provided by CalGrid

CalGrid indicated it does not have any existing land rights along its proposed project route. (L-4)

3.5.7 Information Provided by Horizon West

Horizon West indicated it does not have any existing land rights along its proposed project route. (L-4)

3.5.8 Information Provided by Lotus

Lotus indicated it does not have any existing land rights along its proposed project route. (L-4)

3.5.9 Information Provided by LSPGC

LSPGC indicated it does not have any existing land rights along its proposed project route. (L-4)

3.5.10 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC indicated it does not have any existing land rights along its proposed project route. (L-4)

3.5.11 ISO Comparative Analysis

Comparative Analysis of Experience in Acquiring Rights-of-Way

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the experience of both the project sponsor and its team members in acquiring rights-of-way, including but not limited to experience in the U.S. and California.

The ISO considers experience in acquiring rights-of-way in California to be a slight advantage over experience in rights-of-way acquisition in other jurisdictions because a significant portion of the project will be located in California and such experience will facilitate the timely, efficient, and effective undertaking of the project.

All five project sponsors and their teams have experience in acquiring land rights and site control. Regarding experience in the acquisition of land rights, the ISO has determined that there is no material difference between the experience of CalGrid and Horizon West, because they and their teams have substantial land rights acquisition experience, including experience in California. The experience described by CalGrid and Horizon West is significantly greater than the experience described by Lotus, LSPGC, and VPC, for its two proposals, and the experience of Lotus and VPC, for its two proposals, is slightly better than the experience of LSPGC because they identified California experience in acquiring rights-of-way for transmission lines and LSGPC did not.

Comparative Analysis Incremental Costs Associated with Use of Existing Rights-of Way

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding whether the project sponsor would incur incremental costs in connection with placing new or additional facilities associated with the project on existing rights-of-way.

None of the six proposals of the five project sponsors indicated that the project sponsor expects to incur any incremental costs because of any use of existing rights-of-way for this project. As a result, the ISO has determined that there is no material difference among the six proposals regarding this component of the factor.

Overall Comparative Analysis

Regarding the two components of this factor, as described above, the ISO has determined regarding the first component [experience in the acquisition of land rights] that there is no material difference between the experience of CalGrid and Horizon West, and their experience is better than the experience of Lotus and VPC, for its two proposals, among which there is no material difference, and that the experience of Lotus and VPC, for its two proposals, is slightly better than the experience identified by LSPGC, and regarding the second component [incremental cost] that there is no material difference among the six project proposals. As a result, the ISO has determined that there no material difference between the experience of CalGrid and Horizon West, and their experience is better than the experience of Lotus and VPC, for its two proposals, among which there is no material difference, and that the experience of Lotus and VPC, for its two proposals is slightly better than the experience identified by LSPGC, regarding this factor overall.

3.6 Selection Factor 24.5.4(d): Proposed Schedule and Demonstrated Ability to Meet Schedule

The fourth selection factor is “the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet the schedule of the Project Sponsor and its team.” As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because of the need for this project by the latest in-service date specified in the ISO Functional Specifications, which is particularly important for this project because the timing of this project is critical because it is one of the Southern Area Reinforcement projects identified in the ISO’s 2022-2023 transmission plan as needed to ensure the constraints identified in the plan are addressed. The ISO used the following considerations in its analysis for this component of the factor:

- Proposed schedules
- Scope of activities specified in the proposed schedules
- Amount of schedule float
- Experience of project sponsors
- Potential risks associated with project sponsor's proposal

A proposal that best satisfies this factor will contribute significantly to ensuring that the project sponsor selected will develop the project in a prudent, efficient, cost-effective, and timely manner.

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) the proposed schedule for development and completion of the project and (2) demonstrated ability of the project sponsor and its team to meet that schedule.

Proposed Schedule

(P-3)

3.6.1 Information Provided by CalGrid

CalGrid's proposed project schedule included an in-service date of January 1, 2031, which is 17 months earlier than the ISO's latest in-service date of June 1, 2032. CalGrid indicated that there are four months of float built into its schedule. CalGrid also provided measures that it could take if faced with unanticipated delays such as utilizing, if necessary, price escalation strategies and eminent domain for rights-of-way acquisition, utilizing SB 149 and the Transmission Siting and Economic Development grant program, if applicable, to expedite permitting activities, as well as expediting construction and procurement activities. (P-3)

3.6.2 Information Provided by Horizon West

Horizon West's proposed project schedule included a planned in-service date of December 15, 2029, which is 29.5 months earlier than the ISO's latest in-service date of June 1, 2032, and guaranteed an in-service date of December 31, 2031 which is five months earlier. (P-3)

Horizon West also provided measures it could take if faced with unanticipated delays such as accelerating its permitting schedule, exploring offering higher values or eminent domain for land acquisition, and expediting its construction process by increasing staffing. (P-3)

3.6.3 Information Provided by Lotus

Lotus' proposed project schedule included an expected in-service date of April 5, 2030, which is nearly 26 months earlier than the ISO's latest in-service date of June 1, 2032. (P-3)

Lotus indicated that its schedule contains six months of float, which can be applied to permitting or construction. (P-3)

Lotus also indicated that it could take several steps to achieve an in-service date earlier than the proposed April 2030 date, which could result in some additional costs. (P-3)

3.6.4 Information Provided by LSPGC

LSPGC's proposed project schedule included an expected in-service date of December 1, 2031, which is six months earlier than the ISO's latest in-service date of June 1, 2032. (P-3)

LSPGC did not identify any additional float in its schedule. (P-3)

LSPGC also indicated several measures it could take in case of unanticipated delays, such as additional outreach in case of delays during permitting, allocating additional personnel to engage with landowners, offering incentives, and initiating condemnation proceedings earlier in case of delays in land acquisition. LSPGC also indicated that in the event of a delay during engineering, procurement, and construction, it would use additional personnel to accelerate the schedule. (P-3)

3.6.5 Information Provided by VPC for VPC and VPC Dunes Proposals

For the VPC proposal, VPC's proposed project schedule included an expected in-service date of June 1, 2032, which is same as the ISO's latest in-service date of June 1, 2032. VPC indicated that this schedule contains 173 days of float. (P-3) VPC also proposed an alternate schedule with an expected in-service date of December 31, 2029, which is 29 months earlier than the ISO's latest in-service date of June 1, 2032. VPC indicated that this schedule contains 165 days of float. (P-3)

For the VPC Dunes proposal, VPC's proposed project schedule for its Dunes project included an expected in-service date of June 1, 2032, which is same as the ISO's latest in-service date of June 1, 2032. VPC indicated that this schedule contains 173 days of float for the transmission line and 72 days of float for the switching substation. (P-3) VPC also proposed an alternate schedule with an expected in-service date of December 31, 2029, which is 29 months earlier than the ISO's latest in-service date of June 1, 2032. VPC indicated that this schedule contains 165 days of float for the transmission line and 56 days of float for the substation. (P-3)

VPC indicated that it could take several measures in the event of unanticipated delays, such as condensing the back half of its schedule in case of delays in land acquisition. VPC also indicated that in the event of land, permitting, or construction delays of up to six months, it could take steps such as securing a conditional notice to proceed from the BLM, self-funding certain construction activities prior to closing on financing, increasing the number of construction crews, beginning the construction financing process prior to fully completing permitting, and procuring major equipment from a local utility's inventory. (P-3)

Ability to Meet Schedule

(Prior Projects and Experience Workbook, A-5, P-1, P-2, P-3, P-4)

3.6.6 Information Provided by CalGrid

Past Performance
CalGrid provided schedule performance for 12 200 kV or above transmission line projects that were completed in the past ten years by its team members in the U.S. and internationally, along with their planned and actual in-service dates. The information provided by CalGrid indicated that all twelve projects were completed on or before the planned in-service date. (Prior Projects and Experience Workbook)

Project Management and Team
CalGrid indicated that its project management steps include project kickoff and scoping, schedule development, risk identification and mitigation plans, and cost estimates, and CalGrid provided detailed information for these steps. (P-1)

Regarding project kickoff and scoping, CalGrid indicated that it would host a formal project kickoff meeting where it would confirm that each team member understands the project scope, goals, objectives, and priorities and would define individual priorities and responsibilities. (P-1)

Regarding schedule development, CalGrid indicated that it would utilize the Primavera Enterprise Project Portfolio Management tools to develop a schedule that captures all key tasks and milestones. (P-1)

Regarding risk identification and mitigation plans, CalGrid indicated that its project planning team has developed a framework to provide each team member the means to populate a risk log covering functional areas of expertise and experience. (P-1)

CalGrid described its approach to project management execution, which includes project controls, project communication, quality management, risk management, procurement coordination, and safety management. (P-1)

CalGrid indicated that its construction contractor would use a technology software platform that allows real-time decision-making during all phases of the project. (P-1)

CalGrid also described its approach for developing the project schedule. CalGrid indicated that the project director would have responsibility for maintaining the master schedule from award to COD. (P-1)

CalGrid further indicated that the master project schedule would be progressed weekly and updated monthly and would be developed to ensure delivery of its project within the required commitments made by CalGrid. (P-1)

CalGrid provided information on its project management leadership team that brings decades of experience in management of projects. (P-2)

CalGrid indicated that its leadership team is supported by world-class contractors responsible for project development, planning, permitting, construction, rights-of-way acquisition, public engagement, operations, and maintenance. (P-2)

CalGrid provided the resume of the individual who would be the ISO project director for this project. (A-5)

In addition, CalGrid indicated that it has formed a project advisory team that is available to provide additional support and guidance as necessary throughout the project development, permitting, financing, and construction phases of execution. (P-2)

CalGrid indicated that the project would be executed by the project management team with a single point of contact, its project director. CalGrid indicated that it has assembled a project team with relevant experience in all areas of project execution to provide certainty to the ISO that the project would be delivered on schedule and on budget. (P-1)

Risk Management
CalGrid provided a risk log that included 67 risk items grouped into several risk categories (permitting, procurement, construction, rights-of-way, operations etc.), the risk consequence (cost, schedule) and the likelihood of the risk (low, medium, high). The risk log also included the owner of each risk (CalGrid, ISO), as well as the mitigation measure for each risk item. (P-4)

CalGrid indicated that additional discussions with the Fort Yuma Quechan Tribe would be required to acquire land rights. (L-1) Furthermore, CalGrid indicated if negotiations with the Fort Yuma Quechan Tribe were to fail, it has an alternative route that avoids the tribal lands. (E-2)

CalGrid indicated that it would be sponsoring proposals for two other ISO competitive solicitation projects: (1) Imperial Valley-North of SONGS 500 kV transmission line and substation project; and (2) North of SONGS-Serrano 500 kV transmission line project. CalGrid further indicated that if selected as the approved project sponsor for two or more projects, it would utilize other key staff members with long histories of project management and development experience to take lead project director roles for either one or both of the additional projects and add resources if gaps are identified. CalGrid also indicated that it would critically evaluate the resource availability of key contractors (environmental, engineering, design, and construction) and bid project work out to other capable and qualified contractors to ensure resource availability and timely project execution is not compromised for any additional awarded projects. (P-4)

Financial Incentive
CalGrid's proposal included a schedule completion incentive penalty that would lower the project's return on equity by 2.5 basis points for every full calendar month that the project's energization is delayed beyond June 1, 2032, up to a total of 30 basis points. (P-3)

3.6.7 Information Provided by Horizon West

Past Performance
Horizon West provided schedule performance for 53 200 kV or above transmission line projects that were completed in the past ten years in the U.S. and internationally, along with their planned and actual in-service dates. The information provided by Horizon West indicated that 49 of the 53 transmission line projects were completed on or before schedule and that four projects were delayed. Based on the schedule performance information provided by Horizon West, the average delay in schedule when a project was delayed was one month. The reasons for the delays provided by Horizon West

included delays due to permitting, PSC approval and PPA execution. (Prior Projects and Experience Workbook)

Project Management and Team

Horizon West provided information regarding its five phases of project management, which include project launch and initiation, project planning, project execution, project monitoring and controlling, and project closeout. (P-1)

Regarding project launch and initiation, Horizon West indicated that the project director would oversee the selection of consultants and contractors and allocation of internal resources, as well as identify the metrics to monitor the project during its lifecycle. (P-1)

Regarding project planning, Horizon West indicated that its team would develop a project execution plan, a master project schedule, a project budget, and a risk and issues log, and Horizon West provided additional information for these steps. (P-1)

Regarding project execution, Horizon West indicated that the project management team, led on a day-to-day basis by the project manager, would then begin working on the tasks and milestone deliverables identified within the project execution plan using specific technology platforms to facilitate the exchange of project information, engineering plans, and drawings. (P-1)

Regarding monitoring and control, Horizon West indicated that the project schedule, budget, and risk logs for the project would be updated based on current information. (P-1)

Regarding project closeout, Horizon West indicated that the project team would complete documentation and closeout, including transferring supplier agreements and paying out final invoices upon project completion. (P-1)

Horizon West indicated that Horizon West's senior management team would oversee the project. (P-2)

Horizon West also indicated that a project director would lead a core team comprised of subject matter experts on regulatory, technical services, land, environmental, engineering, construction, procurement, finance, operations and maintenance (O&M), tribal relations, FERC, and legal. (P-2)

Horizon West indicated that its project director would provide a single point of accountability for day-to-day activities, oversee all workstream leads and resources, and be responsible for reporting progress to senior management. (P-2)

Horizon West indicated that its project director would also be responsible for tracking overall progress maintaining that resources are available to keep the project under budget and on schedule. (P-2)

Horizon West provided the resumes of the individuals who would be the early and late-stage project directors for this project. (A-5)

Risk Management

Horizon West provided a risk and issue log that identified 24 high-level set of risks, category of risk, whether it affects cost or schedule, the probability of occurrence, the impact of the occurrence, whether it is a risk during development or construction, and both completed and potential mitigation. (P-4)

Horizon West indicated that the major risks to the project include routing risk, delay in the process of acquiring a certificate of public convenience and necessity (CPCN) from the California Public Utilities Commission (CPUC), and construction cost risk and in each case identified mitigation measures. (P-4)

Horizon West indicated that it is sponsoring more than one project in the ISO's 2022-2023 competitive solicitation process and that its in-service date for each of the three projects would not be affected if selected as the approved project sponsor for two or more of the projects. (P-4)

Financial Incentive
Horizon West indicated that it has committed to a 0.2% reduction in its proposed cap on its annual revenue requirement for each month that the project is delayed beyond the guaranteed in-service date of December 31, 2031, up to a maximum of 1.2%. (P-3)

3.6.8 Information Provided by Lotus

Past Performance
Lotus provided schedule performance for one 200 kV or above transmission line project that is still under construction in the U.S., along with its planned and anticipated in-service date. The information provided by Lotus indicated that this project is delayed by four years due to multiple reasons for delays, which have been explained in quarterly reports to the ISO. (Prior Projects and Experience Workbook).

Project Management and Team
Lotus indicated that through its contractors it would develop plans that include preconstruction, coordination with APS and SDG&E, FERC filings, public outreach plan, and APS and SDG&E interconnection applications. (P-1)

Lotus also indicated that during the preconstruction phase, it would develop plans for procurement, health and safety, project execution, environmental management, electrical studies, interconnection studies, etc. (P-1)

Lotus indicated that its chief executive officer would oversee the successful completion of the project. Lotus also provided the experience of individuals chosen for key positions, such as project manager, environmental and permitting lead, asset manager, land acquisition lead, engineering, procurement, and construction lead, finance lead, and project administrator. (P-2)

Lotus indicated that this project development team has been working together for many years in similar capacities, including working in a similar structure on the project in California and Arizona. Lotus also indicated that the consultants that would support the project development team have worked with Lotus on several projects over the years, including a project in California and Arizona. (P-2)

Lotus provided the resume of the individual who would be the project manager for this project (A-5)

Risk Management
Lotus provided a list of major risks and obstacles that included lack of detailed system data for design, siting and land acquisition, environmental permitting, cost containment, and its ability to develop multiple projects simultaneously. Lotus also provided mitigation measures for these risks and obstacles. (P-4)

Regarding siting and land acquisition, Lotus identified failing to garner the willingness of landowners to participate in negotiations as the highest risk and indicated its experience in anticipating and addressing landowner questions and concerns. Lotus also indicated that its affiliates have the tools and resources to investigate land ownership changes and locate contact information to establish contact with the new landowner. (P-4)

Lotus indicated that additional discussions with the Fort Yuma Quechan Tribe would be required to acquire land rights. (L-1) Furthermore, Lotus indicated if negotiations with the Fort Yuma Quechan Tribe were to fail, it has an alternative route that avoids the tribal lands. (E-2)

Regarding environmental permitting and mitigation, Lotus indicated that its experience with this process for a similar transmission project located in both California and Arizona mitigates the risk associated with this process, which could take several years.

Lotus also indicated that if selected as the approved project sponsor for all three projects in the ISO's 2022-2023 competitive solicitation process, including this project, its team has the capability to effectively develop all three projects simultaneously. (P-4)

3.6.9 Information Provided by LSPGC

Past Performance
LSPGC provided schedule performance for eight 200 kV or above transmission line projects that were completed in the past ten years in the U.S. and internationally, along with their planned and actual in-service dates. The information provided by LSPGC indicated that seven of the eight projects were completed on or before the planned in-service date. The information provided by LSPGC also indicated that one of the eight projects was delayed by three months due to force majeure claimed by the interconnecting transmission owner related to completion of the transmission owner's facilities. LSPGC also indicated that for this project, its affiliate completed its scope of work for the project on schedule and met its obligations to the ISO. (Prior Projects and Experience Workbook).

Project Management and Team
LSPGC provided information for its project management approach, which included risk management, schedule management, cost management, project communication, quality management, issues management, and safety management. (P-1)

Regarding risk management, LSPGC indicated that its risk management process is an iterative cycle of identification, assessment, mitigation, and monitoring. (P-1)

Regarding schedule management, LSPGC indicated that the master schedule it has developed includes schedule dependencies and critical path activities and incorporates the schedules of the project team and subcontractors. (P-1)

Regarding project communication, LSPGC indicated that the project team would rely on a number of communication tools including meetings, written reports, electronic data sharing sites, open houses, planning sessions, project specific website, social media, and media releases. (P-1)

Regarding quality management, LSPGC indicated that it covers all aspects of the project and ensures the project meets all requirements of the solicitation and industry codes and complies with all applicable laws, regulations, standards, guidelines, criteria, permits, and approvals management. (P-1)

Regarding issues management, LSPGC indicated that it follows a seven-step process for the management of issues. (P-1)

LSPGC indicated that it has assembled a team with relevant experience in all areas of project execution and the technical and financial capabilities to design, construct, operate, and maintain the project. (A-5)

LSPGC indicated that it has retained specialized firms to (1) assist with routing, environmental permitting, and regulatory approvals; (2) provide engineering services; (3) construct the transmission line; and (4) provide maintenance and emergency response services. (A-5)

LSPGC indicated that the project's governance structure would utilize a project director, who would be the overall lead, supported by a team of experts organized based on their area of expertise. (P-2)

LSPGC indicated that the project director would the primary point of contact for the ISO and would be responsible for guiding LSPGC's day-to-day activities and overseeing all deliverables from selection as the approved project sponsor until the beginning of operations. (P-2)

LSPGC further indicated that the project director would be dedicated to the project and would be supported by a highly qualified team of managers and subject matter experts with responsibilities for project execution in project development, engineering and procurement, and construction. (P-2)

LSPGC provided the resume of the individual who would be the project director for this project. (A-5)

Risk Management
LSPGC provided a project risk register that included 73 risk items in six risk categories – cost containment, project management and schedule, environmental permitting and public process, land acquisition, engineering and design, and construction. Each risk item included a rating for risk likelihood, risk consequence, risk level to ISO ratepayers, and risk level to LSPGC. Each risk item also included a mitigation measure. (P-4)

LSPGC also identified major risks to the project, such as interest rate increases, equipment and materials cost increases, and regulatory mandated deviations and provided the mitigation measures that it has adopted. (P-4)

LSPGC indicated that if selected as the approved project sponsor for multiple projects in the ISO's 2022-2023 competitive solicitation process, it has the resources to complete the projects on schedule and budget. (P-4)

Financial Incentive
LSPGC indicated that its proposal includes a schedule completion incentive penalty that would lower the project's return on equity by 2.5 basis points for every full calendar month that the project is delayed beyond June 1, 2032, up to a total of 30 basis points. (P-3)

3.6.10 Information Provided by VPC for VPC and VPC Dunes Proposals

Past Performance
VPC provided schedule performance for four 200 kV or above transmission line projects that were completed in the past ten years in the U.S. and internationally, along with their planned and actual in-service dates. The information provided by VPC indicated that two of the four transmission projects were delayed. Based on the schedule performance information provided by VPC, the average delay in schedule when a project was delayed was 12 months. The reasons for the delays provided by VPC for these projects include a CPUC mandate to underground a project post award, additional tower reinforcement identified by the engineers, additional relay work to address compliance requirements, installation of substation equipment to accommodate the increase in amperage, and customer delays due to permitting or not ready to begin. (Prior Projects and Experience Workbook)

Project Management and Team
VPC indicated that its project management approach covers around twenty areas, including resource management, risk management, project administration and document control, safety monitoring and reporting, materials management, construction planning, construction management, permitting, environmental compliance, community outreach, and project close out. (P-1)

VPC indicated that its schedule would encompass all relevant functions and activities of VPC, its partners, and suppliers required for the project. VPC indicated that its project schedule would be an integrated, level 3, critical path method, including work activities, task durations, sequences, milestones, completion dates, restraints, interrelationships between tasks, and critical paths. (P-1)

VPC also indicated that the project schedule would show the interdependence of all activities, including logic ties between each activity. (P-1)

VPC indicated that it has established a dedicated project execution group focused on providing project management, project control, execution planning, and construction expertise throughout the lifecycle of the project. (P-2)

VPC indicated that its project manager would be the primary individual responsible for day-to-day project management activities and would oversee the team leads for each project area (e.g., engineering, land, permitting, public processes, etc.) and would facilitate coordination and communication between each VPC team lead and executives at Grid United, Citizens Energy, and IID. (P-2)

VPC provided the resume of the individual who would be the project manager for this project. (P-2)

VPC also provided information on individuals responsible for budget and schedule management, risk management, construction planning, and execution. (P-2)

Risk Management
VPC indicated that the major risks to the project include permitting delays, cost of private rights-of-way, material and equipment pricing, subsurface conditions, and labor availability. VPC also included the mitigation measures for these risks. In addition, VPC included a risk matrix that identified several financial risks to VPC and the ISO, their probability, impact, and mitigation measures. VPC indicated that this matrix would continue to be updated as the project continues development. (P-4)

VPC indicated that it is sponsoring only one project, which would allow VPC to focus its full attention and resources on the proposed project. (P-4)

VPC indicated it filed a SF-299 form (Application for Transportation, Utility Systems, Telecommunications and Facilities on Federal Lands and Property) and cost recovery agreement with the BLM in 2009, and it has been serialized by the BLM and updated several times since, including the submission of a routing study and draft plan of development in 2019. (E-4)

VPC indicated that it had already submitted to the BLM a draft plan of development and 18 draft mitigation plans and has worked with the BLM to identify possible issues, study requirements, and mitigation measures. VPC indicated that this would allow the BLM's NEPA review and further action on the rights-of-way application to proceed quickly and efficiently after ISO award. (E-4)

Financial Incentive
VPC indicated that its proposal includes a binding annual revenue requirement (ARR) cap for the life of the project that incentivizes it to complete the project on schedule. (P-3)

3.6.11 ISO Comparative Analysis

Comparative Analysis of Proposed Schedule

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding their proposed schedules for development of the project, including but not limited to the scope of activities specified in their schedules and the reasonableness of the timelines they have specified.

All six proposals include schedules that meet the latest in-service date of June 1, 2032, specified in the ISO Functional Specifications, as clarified in the question and answer matrix posted on the ISO website. CalGrid proposed a project schedule that would complete the project 17 months ahead of the ISO's latest in-service date of June 1, 2032. Horizon West proposed a project schedule that would complete the project 29.5 months before the ISO's latest in-service date of June 1, 2032. Lotus proposed a project schedule that would complete the project 26 months before the ISO's latest in service date of June 1, 2032. LSPGC proposed a project schedule that would complete the project 6 months ahead of the ISO's latest in-service date of June 1, 2032. VPC proposed baseline and alternate schedules for its two proposals. For both VPC proposals, the baseline schedule indicated a project completion date of June 1, 2032, which is the same as the latest in-service date specified in the ISO Functional Specifications, and the alternate schedule indicated a project completion date of December 31, 2029. Both schedules are supported by an accelerated completion of the SF-299 process as discussed in Section 3.4.6 regarding the proposed land rights for the project. As discussed above, the ISO considers the potential benefits from an earlier in-service to be uncertain based on the information currently available to the ISO.

All six proposals indicate that the project sponsor could complete the project by the latest in-service date in the ISO Functional Specifications if the start date were to be delayed by six months.

The ISO has determined that all six proposal schedules contain all the expected major activities for the project and contain potentially achievable associated timelines given the ISO's understanding of how long similar activities have taken on projects that have been completed in the recent past in California. In addition, the ISO considers the project sponsors' proposed schedule delay mitigation measures to be comparable.

Several project sponsors proposed schedules with an expected in-service date earlier than the ISO's latest in-service date. However, for the purpose of the comparative analysis for this component of the factor, the ISO considers the potential benefits from an in-service date for this project before the latest in-service date specified in the ISO Functional Specifications to be uncertain based on the information currently available to the ISO. With this in mind, the ISO has chosen to evaluate the project based on the project's ability or likelihood of achieving the latest in-service date specified in the ISO Functional Specifications.

The ISO has determined that, although there are differences in the details in the schedules proposed by each project sponsor, each proposed project schedule includes activities that show that the project sponsors understand the risks they would need to mitigate in order to complete the project by the latest in-service date of June 1, 2032, specified in the ISO Functional Specifications

Overall
The ISO has determined that the schedules in all six proposals of the five project sponsors meet the latest in-service date specified in the ISO Functional Specifications and can meet this date even if the start date were to be delayed by six months and there is no value in completing the project ahead of the latest in-service date. On that basis, the ISO has determined that there is no material difference among the six proposals of the five project sponsors regarding this component of the factor.

Comparative Analysis of Ability to Meet Schedule

The ISO's analysis for this component of the factor focused primarily on the ability of the project sponsors to complete the project by the latest in-service date specified in the ISO Functional Specifications and any potential risks associated with each project sponsor's proposal that might affect completion of the project in a timely manner. For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding their experience, including but not limited to the information in their proposed schedules and their past experience in constructing projects on schedule, accounting for risk management, and performing project management, as well as any other indicated factors that might impact the date of completion.

Previous Experience
The project sponsors and their team members have different levels of experience with previous transmission line projects. CalGrid provided information on 12 transmission line projects, Horizon West provided information for 53 projects, LSPGC for eight projects, and VPC for four projects that were transmission line projects at voltage levels 200 kV or above and completed in the past ten years. Lotus provided information for one project in the U.S. that is 200 kV or above that is still under construction.

Based on the foregoing analysis, the ISO has determined that regarding experience with transmission line projects operating at 200 kV or higher completed in the past ten years, the experience of CalGrid, Horizon West, LSPGC, and VPC is better than the experience of Lotus because its experience is limited to one project.

Regarding completing projects on schedule, the ISO considers that CalGrid, Horizon West, and LSPGC have demonstrated a reasonable degree of success in meeting previous project schedules, although some project sponsors demonstrated more success than others. The schedule performance information provided by these three project sponsors showed that 100% of CalGrid's projects, 92% of Horizon West's projects, and 88% of LSPGC's projects were completed on or ahead of schedule. VPC's schedule performance information showed that 50% of its prior projects were completed on or ahead of schedule. Lotus' schedule performance information showed that it has had relatively less recent experience and success in meeting project schedules. The schedule performance information showed that Lotus has experience with only one transmission line project in the last ten years that is still under construction and is expected to completed past the scheduled date by four years due to multiple reasons.

The schedule performance information provided by CalGrid, Horizon West, LSPGC, and VPC showed an average delay of zero, one, three, and 12 months, respectively, for prior projects that were not completed on schedule. The schedule performance information provided by Lotus for its one prior project showed a delay of four years.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this consideration, the ISO has determined that, based on the specific scope of this project, there is no material difference among the experience of CalGrid, Horizon West, and LSPGC in completing previous projects on schedule and considers their experience to be better than the experience described by Lotus and VPC, for its two proposals. Further, the ISO has determined the experience of VPC, for its two proposals, to be better than that of Lotus in this regard.

Project Management and Team
All five project sponsors have described a reasonable approach to professional project management for their six proposals. All five project sponsors laid out detailed project management programs, as well as identified the teams that will be working on each task of the project.

The project manager or director identified by each project sponsor has at least twenty years of experience, which the ISO considers sufficient.

Based on the foregoing analysis, the ISO has determined that regarding project management and team there is no material difference among the proposals of CalGrid, Horizon West, Lotus, LSPGC, and VPC, for its two proposals.

Project Risk and Management

All five project sponsors included a thorough approach to identifying risks to the project schedule and possible mitigations for those risks. All project sponsors that submitted proposals for more than one project confirmed their ability to work on multiple projects simultaneously, if awarded more than one. VPC indicated that it is submitting proposals for only the North Gila-Imperial Valley #2 500 kV Line project. All project sponsors indicate that they have taken steps to reduce schedule risk.

The ISO has noted in Section 3.4.6 regarding the proposed land rights for the project that the routing proposals of CalGrid and Lotus cross Fort Yuma Quechan Tribal lands, which has the potential of increasing project schedule risk if there are any issues with securing land rights. CalGrid's proposal includes a float of 17 months. Lotus' proposal includes a float of 26 months with an expected in-service date of April 5, 2030. The proposals from both CalGrid and Lotus identified alternative routes in the event they are unable to secure land rights across tribal lands. The ISO has determined that both proposals have substantial float that would be available in case of any delays associated with securing land to cross the Fort Yuma Quechan Tribal lands, which not only would provide additional time to secure tribal land rights but also would provide sufficient time to procure land rights for the alternative routes should tribal land rights be unavailable.

Regarding risks associated with the acquisition of land rights needed for the project, the ISO notes that VPC submitted an SF-299 package to the BLM originally in 2009 for a similar project and recently updated the information for this project. Also, VPC has already submitted a draft plan of development to the BLM. While all proposed schedules of the other project sponsors account for this permitting process, the ISO considers that this gives VPC an advantage regarding a reduction of risk to its project schedule since it can take a year or more for this process.

Based on the foregoing analysis, the ISO has determined that, regarding project risk and risk management, VPC, for its two proposals, has a slight advantage due to its more advanced permitting activities and there is no material difference among the proposals of CalGrid, Horizon West, Lotus, and LSPGC.

Financial Incentive

The proposals of CalGrid and LSPGC include an incentive that would reduce the project return on equity by 2.5 basis points for each full calendar month that the project is delayed beyond June 1, 2032, up to a total of 30 basis points. The proposal of Horizon West includes an incentive that would reduce the annual revenue requirement cap by 0.2% for each month the project is delayed beyond the guaranteed in-service date of December 31, 2031, up to a maximum of 1.2%. The proposals of Lotus and VPC, for its two proposals, do not include any specific incentives for on-time completion of the project. The ISO does not consider VPC's proposed ARR cap to constitute a specific incentive for on-time completion of the project.

The ISO has determined that there is no material difference among the incentives proposed by CalGrid, Horizon West, and LSPGC, and that they are better than the proposals of Lotus and VPC, for its two proposals, because Lotus and VPC did not include any form of specific on-time completion financial incentive.

Overall Component

The ISO has determined that there is no material difference among the six proposals of the five project sponsors regarding project management and team.

The ISO has determined that due to its more advanced permitting activities, the proposals from VPC are slightly better than the proposals of CalGrid, Horizon West, Lotus and LSPGC, among which there is no material difference with respect to project risk.

The ISO has determined that the proposals of CalGrid, Horizon West, and LSPGC are better than the proposals of Lotus and VPC, for its two proposals, regarding the amount of experience constructing transmission line projects over the past ten years and the timely completion of projects over that same time period. Further, the ISO has determined that the two proposals of VPC are better than the proposal of Lotus regarding the amount of experience constructing transmission line projects over the past ten years and the timely completion of projects over that same time period.

The ISO has determined that regarding offering a schedule incentive, that there is no material difference among the proposals of CalGrid, Horizon West, and LSPGC and that they are better than the proposals of Lotus and VPC, for its two proposals, because Lotus and VPC did not include any form of an on-time completion financial incentive.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the proposals of CalGrid, Horizon West, and LSPGC, which are slightly better than the two proposals of VPC, between which there is no material difference, and which are better than the proposal of Lotus, regarding this component of the factor.

Overall Comparative Analysis

The ISO considers the two components of this factor to be of roughly equal importance in the selection process for this project. As discussed above, the ISO has determined that there is no material difference among the proposals of CalGrid, Horizon West, Lotus, LSPGC, and VPC, for its two proposals, regarding the first component of this factor (proposed schedule).

Regarding the second component (demonstrated ability to meet the proposed schedule), based on the foregoing analysis, the ISO has determined that, based on the specific scope of this project, there is no material difference among the proposals of CalGrid, Horizon West, and LSPGC, which are slightly better than the two proposals of VPC, between which there is no material difference, and which are better than the proposal of Lotus, regarding this component of the factor.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the proposals of CalGrid, Horizon West, and LSPGC, which are slightly better than the two proposals of VPC, between which there is no material difference, and which are better than the proposal of Lotus, regarding this factor overall.

3.7 Selection Factor 24.5.4(e): The Financial Resources of the Project Sponsor and Its Team

(Prior Projects and Experience Workbook, F-1 through F-13)

The fifth selection factor is the "financial resources of the Project Sponsor and its team."

The ISO notes that the project sponsors provided substantial information regarding their finances in their applications; however, the ISO has only incorporated relatively limited and general financial information from the project sponsors' proposals in the summaries below due to the sensitive nature of some of the financial information provided.

As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because the North Gila-Imperial Valley #2 500 kV Line project will cost hundreds of millions of dollars and require significant financial resources.

Project sponsors provided information regarding their experience in developing and financing similar projects, annual financial results including key financial metrics, credit ratings, proposed financing sources, and other financial-oriented information requested by the ISO. In performing the comparative analysis, the ISO has considered all of the financial information provided by the project sponsors. The ISO has also utilized two metrics – tangible net worth and Moody's Analytics Estimated Default Frequency ("EDF")[7] – based on information provided in the project sponsors' annual reports. Moody's Analytics EDF has an associated equivalent rating, also provided by Moody's Analytics as part of its EDF calculation, that provides the ISO another metric similar to the agency credit ratings.

Although a company's net worth is sometimes used in financial analysis, it can be misleading because asset and liability values may change dramatically over time. For instance, derivative assets have the potential of changing daily. In addition, there is no prescribed way to value intangible assets. To compensate for these limitations, where possible, the ISO relies on tangible net worth[8], which removes certain assets and liabilities from the net worth calculation. For the purpose of evaluating the financial resources of the project sponsors and their teams for this project, the ISO considers tangible net worth to be more meaningful because it better represents assets that are more immediately available for project funding.

Likewise, the ISO considers that agency credit ratings can have important but limited usefulness in financial analysis because they are largely based on historical performance. In the general course of its business, the ISO has recognized the limitation of credit ratings and has begun to rely on EDF as a more forward-looking measure of a company's financial health. It produces a forward-looking default probability by combining financial statement and equity market information into a highly

[7] Estimated Default Frequency is a proprietary scoring model developed by Moody's Analytics, Inc., a subsidiary of Moody's Corporation (NYSE: MCO).

[8] The ISO Tariff defines "Tangible Net Worth" as total assets minus assets (net of any matching liabilities, assuming the result is a positive value) the CAISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (examples include restricted assets and Affiliate assets) minus intangible assets (*i.e.*, those assets not having a physical existence such as patents, trademarks, franchises, intellectual property, and goodwill) minus derivative assets (net of any matching liabilities, assuming the result is a positive value) minus total liabilities.

predictive measurement of stand-alone credit risk. EDF provides the ISO an additional metric in assessing a project sponsor's ability to see the project through to the end. In addition, the equivalent rating associated with the EDF provides another metric similar to the agency credit ratings. The ISO has utilized both of these additional measures of financial health in its comparative analysis of the financial resources of the project sponsors and their teams for this project.

For the purpose of performing the comparative analysis for this factor, the ISO has considered the following components of the factor:

- Project financing experience
- Project financing proposal
- Financial resources
- Credit ratings
- Financial ratio analysis

The ISO has initially considered these components separately and then developed an overall comparative analysis for financial resources and creditworthiness.

For the consideration of this factor, the ISO has concluded that there are no significant differences between the two proposals submitted by VPC with regard to financial information provided. Consequently, references to VPC and its proposal in this section apply equally to both VPC's proposal without the Dunes Substation and VPC's Dunes proposal.

3.7.1 Information Provided by CalGrid

Project Financing Experience

CalGrid provided a list of several transmission and substation projects that its parent company and affiliated entities have financed in the past ten years. (Prior Projects and Experience Workbook) CalGrid provided information regarding financing of representative projects through its parent and affiliated entities that were similar in type but larger in cost than the expected cost of this project. CalGrid indicated that the representative projects were financed using a project-level financing approach. CalGrid indicated that construction financing would be funded by financial institutions and converted to long-term debt after completion. (F-1, F-11)

Project Financing Proposal

CalGrid indicated that it proposes to create a special purpose entity that would own the assets and facilitate project-level financing to support the construction and operations of the project. CalGrid indicated that it would rely on BETP IV, and its ultimate parent Blackstone, to provide financial support and guarantees for this project. (A-5, F-5)

CalGrid indicated the project would be financed using a combination of debt and equity. CalGrid indicated that Viridon, acting through CalGrid and with the support of the majority owner BETP IV, would invest 100% of the equity required to finance the project and anticipates using debt and equity throughout the project's life. (F-1)

CalGrid indicated that it would act on behalf of Viridon and BETP IV to invest any required equity in the project, would be responsible for arranging the debt associated with the construction of the project, and would service the debt after placing the project in service. CalGrid indicated that it proposes to access the debt markets to lead placement of limited-recourse financing at the project level to support the construction and long-term operation of the project. (F-2, F-5)

CalGrid indicated that BETP IV intends to make a financial commitment to lenders upon financial closing to support the equity requirements of the project and would also provide the appropriate assurances that capital will be sufficient to complete all phases of the construction program account upfront. (F-12)

CalGrid also indicated that it is investigating the possibility of securing project financing through Western Area Power Administration's (WAPA) Transmission Infrastructure Program and various Department of Energy (DOE) programs. (F-12)

To provide further evidence of financial support for the project, CalGrid provided letters of support from two commercial banks. The letters state that they are non-binding and should not be construed as a commitment to finance the project. (F-12.1, F-12.2)

Financial Resources

CalGrid's proposal included a parent support letter signed by an officer from Blackstone indicating support for the project by Blackstone, the ultimate parent of the project's majority owner BETP IV, and that BETP IV would benefit from Blackstone's strong reputation in the financial community. (F-2.2)

CalGrid indicated that CalGrid and the special purpose entity, as wholly owned subsidiaries of Viridon and affiliates of Viridon's majority owner BETP IV, ultimate parent Blackstone, and other Blackstone entities, would benefit from all relevant capabilities and resources of the combined Viridon and Blackstone organizations. (F-5)

CalGrid provided a letter of financial support for the project sponsor financial obligations signed by an officer of BETP IV indicating that appropriate financial assurance instruments would be provided prior to the close of the project's financings and as required by lenders pursuant to the financings of the project. (F-2.1)

CalGrid provided pro forma financial assurance instruments to support the equity funding requirements of the project, which would be effective conditional upon selection of CalGrid as the approved project sponsor and closing of the financing. (F-2.3, F-2.4)

CalGrid provided Blackstone, Inc.'s annual audited financial statements for 2018-2022 and quarterly unaudited financial statements for 2023. (F-3, F-4) CalGrid provided the following information from Blackstone, Inc.'s latest audited financial statements:

Total assets
Total liabilities
Net worth

Credit Ratings

CalGrid indicated that Blackstone, Inc. is a public company and has been rated investment grade by two of the three credit rating agencies. CalGrid provided the following credit ratings and associated credit rating reports for Blackstone, Inc.: (F-6)

Moody's: NR
S&P: A+
Fitch: A+

Financial Ratio Analysis

CalGrid provided the following financial ratios based on Blackstone, Inc.'s audited financial statements: (F-9, F-10)

Funds from operations (FFO)/interest coverage
FFO/total debt
Total debt/total capital
Total assets/total projected capital costs

3.7.2 Information Provided by Horizon West

Project Financing Experience

Horizon West provided a list of several transmission and substation projects that its parent company, NextEra, financed in the past ten years. (Prior Projects and Experience Workbook) Horizon West provided information regarding NextEra's financing of representative projects that were similar in type but primarily larger in cost than the expected cost of this project. (F-11A) Horizon West indicated that the representative projects were financed using limited-recourse term and senior secured variable rate term loans. Horizon West indicated that debt sources included commercial banks. (F-11)

Project Financing Proposal

Horizon West indicated that during the development and construction of the project it would enter into debt financing arrangements and receive equity from NEECH. Upon commercial operations and throughout the life of the project, Horizon West indicated that it plans to finance the project with debt from NEECH and may consider sourcing project financing from the capital markets. Horizon West indicated that it may consider third-party project financing and is exploring debt financing from the DOE. (F-1)

Horizon West provided a letter from NextEra indicating that NEECH would provide appropriate funding and needed guarantees to Horizon West and that those would, in turn, be guaranteed by NextEra as provided for through a blanket guarantee arrangement between NEECH and NextEra. Horizon West indicated that execution of a guaranty would be dependent on the ISO selecting Horizon West as the approved project sponsor and the execution of a mutually agreeable Approved Project Sponsor Agreement with the ISO. (F-2, F-2a, F-2c)

Horizon West indicated that the project would be supported 100% through corporate parent debt and equity funding. Horizon West also indicated that it plans to pursue a variety of DOE programs as a source of debt funding as this type of funding could reduce rates significantly when compared with commercial rates. (F-13)

Financial Resources

Horizon West provided a letter from NextEra, signed by an officer of NextEra, indicating NextEra's financial assurance by guaranteeing the financial obligations of the project. (F-2a)

Horizon West provided NextEra's annual audited financial statements for 2018-2022 and quarterly unaudited financial statements for 2023. Horizon West also provided Horizon West's annual audited FERC Form 1 financial statements for 2022 and FERC Form 3-Q quarterly unaudited financial statements for 2023. (F-3, F-3a, F-4) Horizon West provided the following information from NextEra's latest audited financial statements:

Total assets
Total liabilities
Net worth

Credit Ratings

Horizon West indicated that NextEra is a public company and has been rated investment grade by all three credit rating agencies for the past five years. Horizon West provided the following credit ratings and associated credit rating reports for NextEra: (F-6)

Moody's: Baa1
S&P: A-
Fitch: A-

Financial Ratio Analysis

Horizon West provided the following financial ratios based on NextEra's audited financial statements: (F-9, F-10)

FFO/interest coverage
FFO/total debt
Total debt/total capital
Total assets/total projected capital costs

3.7.3 Information Provided by Lotus

Project Financing Experience

Lotus provided a list of transmission and substation projects that it has financed in the past ten years. (Prior Projects and Experience Workbook) Lotus provided information regarding its financing for representative projects that were similar in type to this project. Lotus provided information showing financing for three projects that were larger in cost than the expected cost of this project. Lotus indicated that the representative projects were financed using project-specific non-recourse construction and permanent debt sourced from institutions. (F-11, Prior Projects and Experience Workbook)

Project Financing Proposal

Lotus indicated that the project would be funded using a combination of debt and equity and that different banks have expressed interest in providing debt financing for the project. Lotus indicated that it would create a special purpose entity as an affiliate for purposes of developing the project. Lotus indicated that the special purpose entity would be managed by Lotus through LIF III and affiliated investment vehicles specifically to finance, construct, own, maintain, and operate the project. (A-5, F-5)

Lotus indicated that the financial structure for construction and working capital would rely on LIF III and that it intends to utilize the WAPA Transmission Infrastructure Program for debt financing. (F-1, F-12)

Lotus indicated that it has received a letter of interest and support confirming WAPA's intent to collaborate with Lotus on the project, but the letter of interest and support is clear that it is not a commitment to fund the project. (F-13)

To provide further evidence of financial support for the project, Lotus provided a letter of support from a commercial bank. The letter is clear that it is non-binding and should not be construed as a commitment to finance the project. (F-1.1) Lotus also provided a parent guarantee letter for financial backing of the project. (F-2.1)

Financial Resources

Lotus indicated it would rely on existing funds or affiliated investment vehicles for financial backing of the project. Lotus indicated that the funds of LIF III and other affiliated investment vehicles are available to support the construction of the project. (F-2)

Lotus provided a written parent guarantee, signed by an officer, providing financial assurance that LIF III, as the direct parent of the special purpose entity that would be formed specifically for this project, would provide customary credit support and has adequate financial resources to provide the financial support for the project repairs and permitting of the project. (F-2.1)

Lotus indicated that it would have limited-recourse debt and plans to support the project once it goes into service. Although lenders would not have financial recourse to Lotus, Lotus indicated that LIF III has sufficient capital to support the construction of the project and any potential liabilities. (F-2)

Lotus provided the following information for LIF III based on quarterly unaudited financial information for 2023 within a letter in lieu of financial statements for 2023: (F-3.2)

Total assets
Total liabilities
Net worth

Credit Ratings

Lotus indicated that LIF III does not have a credit rating. (F-6)

Financial Ratio Analysis

Lotus did not provide audited financial statements or financial ratios. Lotus provided a letter in lieu of financial statements, which Lotus asserted demonstrates that LIF III could meet the financial requirements of the project. (F-3.2)

The ISO calculated the following financial ratio based on the letter in lieu of financial statements provided by Lotus:

Total assets/total projected capital costs

3.7.4 Information Provided by LSPGC

Project Financing Experience

LSPGC provided a list of several transmission and substation projects that its parent, LS Power, financed in the past ten years. (Prior Projects and Experience Workbook) LSPGC provided information regarding LS Power's financing of representative projects that were similar in type to, but some less in cost than, the expected cost of this project. LSPGC indicated that the representative projects were financed with equity-to-debt contributions using a variety of debt sources, including project-specific financing through a number of commercial banks. (F-11) LSPGC also provided information regarding LS Power's previous debt financings and a history of its ability and experience in utilizing the debt markets to consistently raise increasing amounts of capital for financing projects. (F-6)

Project Financing Proposal

LSPGC indicated it is relying on its parent LS Power to satisfy the financial criterion for this project. LSPGC indicated that LS Power intends to access the debt markets to lead placement of limited-recourse financing at LSPGC to support the construction and long-term operation of the project. LSPGC indicated that it would own the assets of the project, would be responsible for arranging the debt associated with construction of the project, and would service the debt after placing the project into service. (F-1)

LSPGC indicated that under the terms of the limited-recourse financing, LSPGC's lenders would not have recourse to LSPGC's parent company, LS Power, but lenders would have access to LSPGC's specific assets, and under an irrevocable equity commitment, they would have recourse to LSPGC's committed equity. LSPGC indicated that LS Power intends to make a financial commitment to the lenders upon financial closing in the form of a letter of credit or other credit support deemed satisfactory by the lenders to support the equity requirements of the project. LSPGC indicated that this equity commitment to lenders would be irrevocable, thereby providing assurances that capital is sufficient to complete all phases of the construction program account upfront. (F-2) LSPGC indicated that it would convert debt used during development and construction or issue new long-term financing to support operations. (F-5)

LSPGC provided evidence of LS Power's financial assurances to LSPGC in the form of a written guarantee. (F-2A)

LSPGC also indicated that it plans to explore federal funding opportunities to obtain lower cost debt for the project and that its parent company, LS Power, has experience in obtaining funding from the DOE. (F-13)

Financial Resources

LSPGC provided a written financial guarantee from LS Power, signed by an officer of LS Power's general partner, indicating LS Power's financial assurance for the project. (F-2A)

LSPGC also provided an equity financing commitment letter, signed by an officer of LS Power's majority owner management company, indicating the majority owner's commitment to provide funding to LS Power for the project. (F-2B)

LSPGC provided LS Power's annual audited financial statements for 2018-2022 and quarterly unaudited financial statements for 2023. (F-3, F-4) LSPGC provided the following information from LS Power's latest annual audited financial statements:

Total assets
Total liabilities
Net worth

Credit Ratings

LSPGC indicated that LSPGC and LS Power are privately held companies that are not rated by credit rating agencies. (F-6)

Financial Ratio Analysis

LSPGC provided the following financial ratios based on LS Power's audited financial statements: (F-9, F-10)

FFO/interest coverage
FFO/total debt
Total debt/total capital
Total assets/total projected capital costs

3.7.5 <u>Information Provided by VPC for VPC and VPC Dunes Proposals</u>

Project Financing Experience

VPC provided a list of several transmission and substation projects financed in the past ten years by companies proposed to be participating in the project. (Prior Projects and Experience Workbook) VPC provided information for three representative projects that were similar in type but primarily larger in cost than the expected cost of this project. VPC indicated that the representative projects of the participating companies were debt financed using either rate-funded financing or commercial banks. (F-11) VPC also provided information regarding the cost and benefits to customers of having participants join the project. (A-4)

Project Financing Proposal

VPC indicated that the project would be funded using a combination of debt and equity. VPC indicated that it is a special purpose entity created for managing the development and construction of the project and that all contracts would ultimately be executed or otherwise assigned to an existing minority owned project company. VPC indicated that the funding costs incurred by the project company in the development and construction phases of the project would be provided by VPC's parent company, Grid United, which would be provided 100% project-level equity for the project from Centaurus and would also raise project-level debt. (A-5)

VPC indicated that IID and Citizens Energy would participate in the project pursuant to a coordination agreement. VPC indicated that it currently owns 40% interest in the project company and through the execution of the coordination agreement, it would have the option to purchase the remaining 60% ownership interest in the project company from STP, and that VPC would be responsible for all of the development costs of the project.

VPC indicated that both IID and Citizens Energy would provide support deposits concurrent with execution of the coordination agreement. (A-5 Coordination Agreement)

VPC indicated that after the award it plans to exercise its option to purchase, and then, at the commercial operation date, IID would purchase a portion of the transmission capacity associated with the project and Citizens Energy would have the option to lease a portion of the transmission capacity through the use of a wholly owned subsidiary. VPC indicated that both capacity transactions would require investments by the participants in amounts equal to a proportion of development costs incurred less the amount of each of their deposits. (A-5 Coordination Agreement)

VPC also provided a separate agreement indicating that conditionally Citizens Energy would have the option to purchase a portion of the equity interest of the project company in lieu of the option to lease transmission capacity per the coordination agreement. (A-5 Citizens Energy letter agreement)

VPC indicated that it is tracking federal funding programs to identify opportunities to lower the cost of the project. (F-13)

To provide further evidence of financial support for the project, VPC provided a letter of support from a commercial bank. The letter is clear that it is non-binding and should not be construed as a commitment to finance the project. (F-2)

Financial Resources

VPC indicated it would rely on Centaurus, its parent company, for the financial backing of equity for the project, which would be available to support the construction and development of the project. (F-2) VPC provided a financial commitment letter, signed by an officer, providing financial assurance that Centaurus, as the direct parent of VPC, would provide equity and has adequate financial resources to provide the financial support for the project to either VPC or Grid United for the project company. (F-2)

VPC indicated that with the assistance of Grid United it expects to raise debt financing for the project and any remaining capital requirements for the project. VPC indicated that debt financing could include a combination of bank and private placement issuances. (F-2)

VPC provided a coordination agreement describing the roles and responsibilities of the participating entities that would support the project during development and once it goes into service. The agreement indicated that VPC has an option agreement to purchase 100% of the equity interest in the project company but that all assets of the project would be owned by the project company. (A-5) VPC indicated that it is a special purpose entity created for the project and would not have financial recourse to Grid United, its parent Centaurus, or any affiliated entities. (F-2)

VPC provided the following information for Grid United based on annual audited financial statements for 2021 and 2022. VPC also provided the following information for VPC based on annual unaudited financial statements for 2022 and quarterly unaudited financial statements for 2023 for Grid United and VPC: (F-3, F-4)

Total assets
Total liabilities
Net worth

Credit Ratings

VPC indicated that neither VPC nor Grid United has credit ratings. (F-6)

Financial Ratio Analysis

VPC provided financial ratios for Grid United based on audited financial statements with and without IID's participation in the project. VPC asserted that Grid United's equity commitment from Centaurus and VPC's equity investment demonstrate that VPC could meet the financial requirements of the project. (F-9, F-10)

FFO/interest coverage
FFO/total debt
Total debt/total capital
Total assets/total projected capital costs

3.7.6 ISO Comparative Analysis

For the purpose of performing the comparative analysis for this factor, the ISO has considered the following components of the factor:

- Project financing experience
- Project financing proposal
- Financial resources
- Credit ratings
- Financial ratio analysis

The ISO has initially considered these components separately and then developed an overall comparative analysis for financial resources.

The ISO's analysis of the financial resources of the project sponsor and its team has focused primarily on whether each project sponsor has adequate financial resources and creditworthiness to finance the project and whether constructing, operating, and maintaining the facilities would significantly impair the project sponsor's creditworthiness or financial condition.

For purposes of the comparative analysis for this factor, the ISO has primarily considered the project sponsors' representations. In addition, the ISO considered each project sponsor's audited financial statements, credit ratings, and associated ratings reports from one or more of the credit rating agencies. In instances where a project sponsor is looking to an affiliated entity (e.g., a corporate parent) for financial support on the project, the ISO used financial statements and credit ratings of the affiliated entity if the affiliated entity provided a letter of assurance, signed by an officer of the company, stating that it would provide unconditional financial support to the project.

Although there are slight differences among project sponsors regarding some of the components considered, including the financial strength of the company ultimately backing the project and that company's credit ratings, the ISO does not consider these differences significant enough to materially affect any one project sponsor's ability to complete this project, considering the project cost estimates. Consequently, this comparative analysis relies in large part on minor degrees of difference.

Project Financing Experience

Based on the information provided and representations by the project sponsors, the ISO has determined that over the past ten years, Horizon West identified considerably more transmission project financing experience than CalGrid, LSPGC, Lotus, and VPC. Although CalGrid, LSPGC, and Lotus identified less transmission project financing experience than Horizon West, their financing experience exceeded the experience of VPC during the past ten years. CalGrid provided information showing financing of multiple projects of similar type but larger in cost than the expected cost of this project. Horizon West provided information showing financing of transmission projects of similar type but primarily larger in cost than the expected cost of this project. Lotus provided information showing the financing of three transmission projects that were of similar type but larger in cost than the expected cost of this project. LSPGC provided information showing financing of some similar types of transmission projects, but some were lower in cost than the expected cost of this project. VPC provided information regarding financing of participant company projects that were of similar type but primarily larger in cost than the expected cost of this project.

Although Horizon West demonstrated more transmission project financing experience than CalGrid, Lotus, LSPGC, and VPC in the past ten years, and CalGrid, Lotus, and LSPGC demonstrated more transmission project financing experience than VPC in the past ten years, the ISO has concluded that CalGrid, Lotus, LSPGC, and VPC sufficiently demonstrated their ability to secure project financing for this project. Consequently, the ISO considers the project financing experience of all five project sponsors for their six proposals to be sufficient such that there is no material difference among them regarding the extent to which their project financing experience has a bearing on their ability to finance this particular project.

Project Financing Proposal

Based on the financial proposals provided by each of the project sponsors, all project sponsors will finance the project using a combination of both equity and debt. Equity for the project will be provided by the parent or an affiliate company of the project sponsor. Debt will be provided directly through the existing capital and/or credit facilities of the parent or through capital markets or financial institutions by either the project sponsor or the parent company. Debt provided during construction by the parent company may be converted into long-term debt once the project goes into operation. Some project sponsors intend to use limited-recourse debt financing with lenders. The project sponsors' capital structures are generally within a close range of each other regarding debt and equity.

Each of the project sponsors provided either a letter of financial assurance or guarantee from its parent company or affiliate for the financial obligations of the project.

As an alternative to sourcing financing from the capital markets, CalGrid, LSPGC, Horizon West, Lotus, and VPC indicated they are investigating the possibility of securing project financing through WAPA's Transmission Infrastructure Program or one or more of the DOE's programs. Lotus received a letter of interest and support confirming WAPA's interest in leading a financing to support bids by Lotus for the project, but the letter of interest and support is clear that it is not a commitment to fund the project.

Based on all five project sponsors' reliance on parent funding and access to the capital markets, the ISO finds no material difference in their funding proposals.

Financial Resources

Each project sponsor has access to a parent or an affiliate and the capital markets and financial institutions for financing this project. All of the parent or affiliate companies of the project sponsors will provide equity for the project based on equity to total capital ratios that are in accordance with industry practice. Some of the project sponsors have debt financing experience with the capital markets or financial institutions, and all of the project sponsors have access to parent or affiliate funding to fulfill the balance of debt required to cover the cost of the project. The parent or affiliate companies of the project sponsors also provided either a letter of guarantee or financial assurance to support the financial obligations of the project.

Based on the information provided by the project sponsors, the ISO has determined that CalGrid's parent company, Blackstone, and Horizon West's parent company, NextEra, are strongest regarding this particular measure, followed by LSPGC's parent company, LS Power, which is stronger than both Lotus' affiliate company, LIF III, and VPC's parent company, Centaurus. Strength in this factor can help minimize the financial risk that a project may not be completed.

The ISO also calculated a tangible net worth for the parent companies of three of the project sponsors and has concluded that the parents of CalGrid and Horizon West have shown higher tangible net worth than LSPGC's parent company over the past five years. Lotus and VPC did not provide sufficient information for the ISO to calculate a tangible net worth for Lotus' or VPC's affiliates; thus, the ISO was unable to compare Lotus and VPC to the other project sponsors regarding this measure of financial strength.

Having the financial capacity to continue to bid on, win, and finance projects, although dependent in part on the financial resources of a company, also depends on the breadth and strength of a company's partners and banking relationships. The ISO has concluded that the proposals of CalGrid and Horizon West are the strongest in this regard, followed by LSPGC's proposal, then Lotus' proposal, and then VPC for its two proposals. LSPGC, Lotus, and VPC have developed banking relationships as evidenced by various banks providing support for this project. Consequently, the ISO considers LSPGC, Lotus, and VPC, for its two proposals, to have sufficient financial resources to complete this project, although CalGrid and Horizon West, for their proposals, are stronger with regard to this consideration. Given the cost estimates for this project, considering the analysis discussed above, and given the inability of the ISO to calculate a tangible net worth for Lotus and VPC and their affiliates, the ISO considers LSPGC and its proposal to be stronger than Lotus and VPC and their proposals regarding this particular measure of financial strength.

Credit Ratings and Estimated Default Frequency

Public companies are typically rated by three major credit rating agencies, Moody's, S&P, and Fitch. Credit ratings are opinions about a company's relative creditworthiness. They provide a common standard for lenders to determine whether or not a company will pay its debts on time and in full.

Of the five project sponsors, two of their parent or affiliate companies are public and three are private. Both of the public companies had investment grade ratings from each of the credit agencies for the past five years. Investment grade ratings are an indication that the company is at low risk of default for creditworthiness purposes.

CalGrid and Horizon West are backed by independently rated, investment grade companies. Although their individual ratings vary somewhat, the ISO does not consider these differences to be material for purposes of assessing the ability of these companies to obtain sufficient funding to construct this project. LSPGC's parent LS Power and Lotus' and VPC's affiliate companies are not independently rated by any of the three major credit rating agencies. The lack of a credit rating is not unusual, and the ISO has not considered it an adverse factor in this analysis or prior analyses.

In addition to available credit ratings, the ISO also used Moody's Analytics Estimated Default Frequency (EDF) report and equivalent credit ratings to assess whether a company is likely to default on its loan payments over a given period where the assets of a company go below its outstanding debt obligations that need to be paid. EDF reports were available for three of the five parent or affiliate companies of the project sponsors, for each of the past five years.

The EDF scores and equivalent ratings of the parent companies of CalGrid and Horizon West were lower than LSPGC's parent company's EDF scores and equivalent ratings for each of the five years. Lotus and VPC did not provide sufficient information to generate the EDF report for Lotus' or VPC's affiliate companies; thus, the ISO was unable to compare Lotus and VPC to the other project sponsors regarding this measure of financial strength.

Additionally, each of the project sponsors declared that neither it nor its parent or affiliate company had a history of payment default or bankruptcy in the past five years.

Given the information provided and based on the Moody's Analytics EDF report and the resulting Moody's Analytics equivalent rating for the past five years, the ISO considers the proposals of CalGrid and Horizon West to be stronger than the proposal of LSPGC. The ISO relies on the EDF report and equivalent ratings as an additional financial metric to assess the probability that a company will default on its payments within a specified period of time. None of the EDF scores and equivalent ratings were unacceptable, but there were differences in the EDF scores and equivalent ratings of CalGrid and Horizon West compared to LSPGC, as discussed above. As noted, the ISO was unable to compare Lotus and VPC, for its two proposals, to the other project sponsors regarding this consideration.

Financial Ratio Analysis

CalGrid, Horizon West, and LSPGC provided audited financial statements for the past five years for their parent companies. Based on this information, CalGrid, Horizon West, and LSPGC provided interest and debt coverage, debt to capital, and total assets to projected capital costs of the project ratios in their proposals. These financial ratios provide insight into the operational trends of the parent companies of those three project sponsors over the past five years.

Financial ratios provide the ISO insight into a project sponsor's ability to pay interest and service debt out of funds from its operating activities as well as how leveraged a company is in terms of its total debt obligations. The interest and debt coverage ratios are an indicator of how many times interest and debt are covered by the parent company's operating income in each of the past five years.

The coverage ratios vary depending on industry and the capital-intensity of a company's operations. Based on the prior project and financing experience and other information provided in the project proposals of CalGrid, Horizon West, and LSPGC, their parents are involved with large infrastructure projects, and the timing of cash flows of certain projects may be unpredictable and thus should not by itself affect their ability to finance the project.

The total debt to capital ratio of each of CalGrid's, Horizon West's, and LSPGC's parent companies for each of the past five years indicated no risk of extensive financial leverage because the company's debt obligations do not exceed its capital balance.

Based on a comparison of the project sponsors' financial ratios, the ISO considers the interest and debt coverage ratios and debt to capital ratios of CalGrid and Horizon West to be better than LSPGC's financial ratios for those measures. Lotus did not provide information on which the ISO could base a determination of all of the financial ratios that the ISO typically uses to evaluate the financial strength of a project sponsor. VPC provided less than five years of information, which was not enough information for the ISO to base a determination of all of the financial ratios that the ISO typically uses to evaluate the financial strength of a project sponsor. The ISO was unable to calculate financial ratios other than total assets to total project cost for Lotus and was unable to use the information from VPC to make appropriate comparisons; thus the ISO was unable to compare Lotus and VPC to the other project sponsors regarding this measure of financial strength.

As discussed above, CalGrid and Horizon West have better financial ratios than LSPGC, the ISO was unable to calculate financial ratios for Lotus, and VPC provided less than five years of financial ratio history, precluding the ISO from making a comparison regarding its financial ratios. As a result, the ISO considers the proposals of CalGrid and Horizon West to be stronger than the proposal of LSPGC, and the ISO is unable to compare these proposals to Lotus and VPC, for its two proposals, regarding this consideration.

Overall Analysis

In performing the comparative analysis for this factor, the ISO considered all of the financial information provided by the project sponsors as well as the additional information developed by the ISO described above. The ISO's assessment of the financial resources of the project sponsors and their teams is necessary for the ISO to determine which of the project sponsors can bring the strongest financial resources to bear in order to fully finance the project over its life span at a competitive cost and to complete the project under a range of possible scenarios (*e.g.*, construction delays, cost escalation, regulatory interventions, etc.). This comparative analysis relies in large part on minor degrees of difference.

Based on the information provided by the project sponsors, the ISO has concluded that each project sponsor has sufficiently demonstrated the experience and financial resources to undertake a project of this scope and cost. Also, as discussed above, the ISO considers there to be no material differences among the project sponsors and their proposals regarding project financing experience and project financing proposals, especially when compared to the other differences among the project sponsors and their proposals. As discussed in detail above, the ISO considers CalGrid and Horizon West to have an advantage over LSPGC, Lotus, and VPC in the area of financial resources and considers LSPGC to have an advantage over Lotus and VPC in this area. The ISO also considers CalGrid and Horizon West to have an advantage over LSPGC in the area of credit ratings and EDF and the area of financial ratio analysis. The ISO is unable to compare Lotus and VPC to the other project sponsors regarding credit ratings and EDF and regarding financial ratio analysis.

Based on the foregoing, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the scope of this particular project, there is no material difference between CalGrid and its proposal and Horizon West and its proposal, and they are better than LSPGC and its proposal, which is slightly better than Lotus and its proposal and VPC and its two proposals, among which there is no material difference, regarding this factor.

3.8 Selection Factor 24.5.4(f): Technical (Environmental Permitting) and Engineering Qualifications and Experience

The sixth selection factor is "the technical and engineering qualifications and experience of the Project Sponsor and its team." As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because experience with environmental permitting and transmission project engineering can contribute to lower project cost, reduced permit acquisition efforts, and reduction in the overall time needed to complete the project.

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) the technical (environmental permitting) qualifications and experience of the project sponsor and its team and (2) the engineering qualifications and experience of the project sponsor and its team.

Technical (Environmental Permitting) Qualifications and Experience

(Prior Projects and Experience Workbook, E-1, E-2, E-3, E-4, E-5a)

3.8.1 Information Provided by CalGrid

CalGrid indicated that it and its team would submit an application for a CPCN and Proponent's Environmental Assessment with the CPUC.

CalGrid indicated that it and its team would submit permit applications to the following federal agencies:

- BLM rights-of-way (permanent and temporary)
- U.S. Army Corps of Engineers Clean Water Act-Section 10.
- U.S. Fish and Wildlife Service Endangered Species Act Section 7.
- U.S. Bureau of Reclamation rights-of-way and use authorization.
- Department of Defense consultation for flight paths near military facilities.
- Federal Aviation Administration consultation for flight paths near civilian airports.
- Bureau of Indian Affairs Trustee for Fort Yuma Quechan Tribe rights-of-way grant
- Advisory Council on Historic Preservation Section 106 consultation.
- Department of Homeland Security / Border Patrol consultation
- U.S. Department of Agriculture resource conservation consultation

- Environmental Protection Agency Comprehensive Environmental Response, Compensation and Liability Act. Phase 1 review.

Expected California permits:
- CPUC CPCN and CEQA review. AB 52 tribal consultation.
- Colorado River Basin Regional Water Quality Control Board water discharge permit.
- California Department of Fish and Wildlife Section 2081 incidental take permit and 2081.1 determination for effects on species that are both state and federally listed, mitigation plan for rare plants, lake and streambed alteration permit.
- California State Historic Preservation Office Section 106 consultation.
- California State Lands Commission rights-of-way for Colorado River crossing.

Expected Arizona permits:
- Arizona Corporations Commission (ACC) certificate of environmental compatibility
- Arizona State Land Department rights-of-way Colorado River.
- Arizona Department of Game and Fish consultation.
- Arizona Regional Water Quality Control Board general construction stormwater permit.
- Arizona Advisory Council on Historic Preservation Section 106 consultation.

Expected local permits:
- Imperial County encroachment permit, grading permit, traffic control permit, transportation permit, and air quality permit.

CalGrid indicated it contacted a representative of the Fort Yuma Quechan Tribe and was told additional discussions were required. (E-1, E-2, E-3, E-4, E-5a)

Furthermore, CalGrid indicated if negotiations with the Fort Yuma Quechan Tribe failed, it has an alternative route that avoids the tribal lands. (E-2)

CalGrid provided a list of its experience and the experience of its contractors with obtaining permits for transmission line projects. This list included 26 transmission line projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., with 19 in California. (Prior Projects and Experience Workbook)

3.8.2 Information Provided by Horizon West

Horizon West indicated that it and its team would submit an application for a CPCN and Proponent's Environmental Assessment with the CPUC.

Horizon West indicated that it and its team would submit permit applications to the following federal agencies:
- BLM rights-of-way (permanent and temporary)
- U.S. Bureau of Reclamation rights-of-way and use authorization.
- U.S. Army Corps of Engineers Clean Water Act Section 404, NWP 57
- U.S. Fish and Wildlife Service Endangered Species Act Section 7

Expected California permits:

- CPUC CPCN and CEQA review
- Colorado River Basin Regional Water Quality Control Board Section 401 water quality certification, storm water pollution protection plan
- California Department of Fish and Wildlife Section 2081 incidental take permit and 2081.1 consistency with federal species mitigation plan for rare plants, Section 1600 lake and streambed alteration permit
- California State Lands Commission lease, Colorado River

Expected Arizona permits:

- ACC certificate of environmental compatibility
- Arizona Department of Environmental Quality Clean Water Act Section 401 WQC
- Arizona Department of Environmental Quality general construction stormwater permit
- Arizona State Land Department rights-of-way Colorado River

(E-1, E-2, E-3, E-4, E-5a)

Horizon West provided a list of its experience and the experience of its contractors with obtaining permits for transmission line projects. This list included 210 transmission line projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., with 37 in California. (Prior Projects and Experience Workbook)

3.8.3 Information Provided by Lotus

Lotus indicated that it and its team would submit an application for a CPCN and Proponent's Environmental Assessment with the CPUC.

Lotus indicated that it and its team would submit permit applications to the following federal agencies:

- BLM rights-of-way (permanent and temporary)
- U.S. Bureau of Reclamation rights-of-way and use authorization
- U.S. Army Corps of Engineers Clean Water Act Section 404, NWP 57
- U.S. Fish and Wildlife Service Endangered Species Act Section 7
- Bureau of Indian Affairs rights-of-way grant
- Advisory Council on Historic Preservation- Section 106 consultation

Expected California permits:

- CPUC CPCN and CEQA review
- Colorado River Basin Regional Water Quality Control Board Section 401 water quality certification, storm water pollution protection plan
- California Department of Fish and Wildlife Section 1602 lake and streambed alteration permit.
- California Department of Parks and Recreation encroachment permit
- Caltrans encroachment permit
- California State Lands Commission lease, Colorado River

Expected Arizona permits:

- ACC certificate of environmental compatibility
- Arizona Department of Environmental Quality Clean Water Act Section 401 WQC
- Arizona Department of Environmental Quality general construction stormwater permit
- Arizona State Land Department rights-of-way Colorado River

(E-2, E-3)

Lotus indicated it would seek for this project to be included under Title 41 of the Fixing America's Surface Transportation Act (FAST-41). If the project were to be included as a FAST-41 covered project, Lotus indicated that the Federal Permitting Improvement Steering Council would coordinate all federal environmental reviews and authorizations for this project. (E-1)

Lotus indicated it has not finalized negotiations with representatives from the Fort Yuma Quechan Tribe concerning the route across tribal lands. Furthermore, Lotus indicated if negotiations with the Fort Yuma Quechan Tribe failed, it has identified an alternative route that avoids the tribal lands. (L-1, E-1, E-2, E-3, E-4, E-5a)

Lotus provided a list of its experience and the experience of its contractors with obtaining permits for transmission line projects. This list included 11 transmission line projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., with seven in California. (Prior Projects and Experience Workbook)

3.8.4 Information Provided by LSPGC

LSPGC indicated that it and its team would submit an application for a CPCN and Proponent's Environmental Assessment with the CPUC.

LSPGC indicated that it and its team would submit permit applications to the following federal agencies:

- BLM rights-of-way (permanent and temporary)
- BLM Section 106 programmatic agreement (historic preservation)
- U.S. Bureau of Reclamation rights-of-way and use authorization
- U.S. Army Corps of Engineers Clean Water Act Section 404, NWP 57, Rivers and Harbors Act Section 10
- U.S. Fish and Wildlife Service Endangered Species Act Section 7 biological opinion, incidental take permit

Expected Arizona permits:

- ACC certificate of environmental compatibility
- Arizona State Land Department rights-of-way Colorado River
- Arizona Department of Transportation encroachment permit

Expected California permits:

- CPUC CPCN and CEQA review
- Colorado River Basin Regional Water Quality Control Board Section 401 water quality certification

- California Department of Fish and Wildlife Section 2081 incidental take permit and 2081.1 consistency with federal species, Section 1600 lake and streambed alteration permit
- Caltrans encroachment permit
- California State Lands Commission lease, Colorado River

(E-1, E-2, E-3, E-4, E-5a)

LSPGC provided a list of its experience and the experience of its contractors with obtaining permits for transmission line projects. This list included ten transmission line projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., with one project in California. (Prior Projects and Experience Workbook).

3.8.5 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC indicated that it and its team would submit an application for a CPCN with the CPUC and a CEQA review with the Imperial Irrigation District.

VPC indicated that it and its team would submit permit applications to the following federal agencies:

- BLM rights-of-way (permanent and temporary)
- BLM Section 106 programmatic agreement (historic preservation)
- U.S. Bureau of Reclamation rights-of-way and use authorization
- U.S. Army Corps of Engineers Clean Water Act Section 404, NWP 57
- U.S. Fish and Wildlife Service Endangered Species Act Section 7 biological opinion, incidental take permit.
- Department of Defense consultation to confirm no effect
- U.S. Border Patrol consultation for project near the border
- Federal Aviation Authority confirmation of no hazard

Expected Arizona permits

- ACC certificate of environmental compatibility
- Arizona State Land Department rights-of-way Colorado River
- Arizona Game and Fish Department consultation
- Arizona Department of Environmental Quality general construction activity stormwater permit
- Arizona State Historic Preservation Office Section 106 consultation

Expected California permits

- Imperial Irrigation District CEQA review
- CPUC CPCN
- Colorado River Basin Regional Water Quality Control Board Section 401 water quality certification
- California Department of Fish and Wildlife Section 2081 incidental take permit and 2081.1 consistency with federal species, Section 1600 lake and streambed alteration permit
- Caltrans encroachment permit
- California State Historic Preservation Office Section 106 consultation
- California State Lands Commission rights-of-way, Colorado River

VPC indicated it currently has an accepted SF-299 form and cost recovery agreement before the BLM, which was filed in 2009 and recently updated for this project. VPC indicated that it had already submitted to the BLM a draft plan of development and 18 draft mitigation plans and has worked with the BLM to identify possible issues, study requirements, and mitigation measures. VPC indicated that this would allow the BLM's NEPA review and further action on the rights-of-way application to proceed quickly and efficiently after ISO award. (E-1, E-2, E-3, E-4, E-5a)

VPC provided a list of its experience and the experience of its contractors with obtaining permits for transmission line projects. This list included 12 transmission line projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., with four in California. (Prior Projects and Experience Workbook)

For the VPC Dunes proposal, VPC provided a list of its experience and the experience of its contractors with obtaining permits for substation projects. This list included three substation projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., with two in California. (Prior Projects and Experience Workbook).

Engineering Qualifications and Experience

(Prior Projects and Experience Workbook, A-5, QP-1, QP-2, P-4, P-5, S-1 through S-8, T-1 through T-8)

3.8.6 Information Provided by CalGrid

CalGrid provided a list of its experience and the experience of its contractors with designing transmission line projects. The list included 31 transmission line projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years and are located in the U.S., with 11 in California. (Prior Projects and Experience Workbook)

CalGrid indicated that the proposed transmission line design is consistent with the ISO Functional Specifications for the project. (QP-1) CalGrid indicated that that the proposed design satisfies applicable reliability criteria and ISO planning standards. (QP-2) CalGrid indicated that it had evaluated several risk categories (permitting, procurement, construction, rights-of-way, operations etc.), the risk consequence (cost, schedule), and the likelihood of the risk (low, medium, high) and developed mitigation measures. (P-4) CalGrid identified common design and construction risks and challenges that its general construction contractor could encounter, including permitting, access work complications, landowner relations, federal and indigenous engagement, geotechnical and environmental issues, and designing for crossing bodies of water, critical (threatened or endangered) species habitats, or railroads. (P-5)

CalGrid provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the 500 kV transmission line, including codes and standards and CPUC General Order (GO) 95 and National Electrical Safety Code (NESC) requirements. CalGrid identified structure types, a two-conductor bundle ACSS (aluminum conductor steel supported), span lengths of 1,000 feet, transmission line crossing, and rights-of-way width and provided the ampacity for an ambient temperature of 50°C, total impedance, and termination at existing substations. (T-1 to T-8)

3.8.7 <u>Information Provided by Horizon West</u>

Horizon West provided a list of its experience and the experience of its contractors with designing transmission line projects. The list included 15 transmission line projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with one in California. Horizon West also indicated that it has prior experience with three out of five of its proposed contractors with design experience. (Prior Projects and Experience Workbook)

Horizon West indicated that its proposal satisfies the ISO Functional Specifications for the project. (QP-1) Horizon West indicated that the design has been verified to satisfy all applicable reliability planning standards, criteria, and guidelines and has applied design and performance criteria from the North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and ISO. (QP-2) Horizon West indicated that potential engineering risks associated with the project include unexpected subsurface conditions, route changes, FAA hazard determination, and requirements to change conductor, structures, or foundations. (P-4) Horizon West indicated that it has faced design-related risks and challenges similar to those foreseen for the project, such as field conditions that are inconsistent with initial design basis, and further indicated that it has mitigated this risk by including an upfront assessment of the project-specific requirements. (P-5)

Horizon West provided detailed design criteria for an 82-mile 500 kV transmission line that included codes and standards and CPUC GO 95 and NESC requirements and detailed engineering routing criteria. Horizon West identified structure types, a two-conductor bundle ACSR (aluminum conductor steel reinforced), span lengths of 1,500 feet, transmission line crossings, termination at existing substations, right-of-way width, and the ampacity for an ambient temperature of 50°C and total impedance. (T-1 to T-8)

3.8.8 <u>Information Provided by Lotus</u>

Lotus provided a list of its experience and the experience of its contractors with designing transmission line projects. The list included 43 transmission line projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with 13 in California. Lotus also indicated that it has prior experience with two of its proposed contractors that would be involved with project design and engineering. (Prior Projects and Experience Workbook)

Lotus indicated that the project has been designed to meet or exceed the requirements of the functional specification. (QP-1) Lotus indicated that ISO Tariff Sections 24.5.3.2 (a) & (b) and the ISO Planning Standards were considered in designing the proposed project and that it would be designed with two diverse forms of telecommunication to support the WECC guidelines. (QP-2) Lotus indicated that the major risks to the project include lack of detailed system data, siting and land acquisition, environmental permitting, and mitigation cost containment. (P-4) Lotus indicated that the engineering risks associated with the project are similar to most transmission lines constructed in the desert southwest and that Lotus and its design and construction contractor have encountered and successfully overcome challenges on multiple projects in this region and identified specific risks for physical foundation design and interconnection coordination and engineering requirements with the incumbent utilities. (P-5)

Lotus provided detail design criteria for a 72.5-mile 500 kV transmission line that included codes and standards and CPUC GO 95 and NESC requirements and detailed routing criteria, including environment concerns. Lotus identified structure types, a two-conductor bundle “TR” (aluminum conductor with carbon fiber core), span lengths of 1,750 feet, transmission line crossings, termination at existing substations, right-of-way width, and the ampacity for an ambient temperature of 50°C and total impedance. (T-1 to T-8)

3.8.9 Information Provided by LSPGC

LSPGC provided a list of its experience and the experience of its contractors with designing transmission line projects. The list included 12 transmission line projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with none in California. LSPGC also indicated that it has prior experience with both of its proposed design and engineering contractors. (Prior Projects and Experience Workbook)

LSPGC indicated that the project has been designed to meet or exceed the needs identified in the ISO transmission plan, including the ISO Functional Specifications and all applicable standards, and that all transmission components meet or exceed the requirements of CPUC General Order No. 95, Grade B requirements, the NESC, Grade. (QP-1) LSPGC indicated that the design satisfies all applicable reliability criteria and ISO planning standards, including the ISO Functional Specifications and that the project would meet all NERC reliability guidelines. LSPGC also indicated that the transmission line design for the project meets or exceeds applicable IEEE, ASCE, CPUC GO 95, and NESC requirements. (QP-2) LSPGC indicated that major risks to the project include the route, design, schedule, and monitoring and mitigation strategy and that the project route and design were carefully crafted to avoid impacts to sensitive areas or minimize impacts when sensitive areas could not be completely avoided. (P-4) LSPGC’s proposal included a list of potential project engineering risks that included final structure placement, FAA hazard determination, wetlands impacts, changes to detail design, unforeseen soil conditions, errors and omissions in design, and the possibility that final electrical studies may require modifications to design. (P-5)

LSPGC provided detail design criteria for an 87-mile, 500 kV transmission line that included codes and standards and CPUC GO 95 and NESC requirements and detailed engineering routing criteria. LSPGC identified structure types, a three- conductor bundle ACSR (aluminum conductor steel supported), span lengths of 1,330 feet, transmission line crossings, termination at existing substations, right-of-way width, and the ampacity for an ambient temperature of 50°C and total impedance. (T-1 to T-8)

3.8.10 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC provided a list of its experience and the experience of its contractors with designing transmission line projects. The list included 15 transmission line projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with six in California. VPC also indicated that it has prior experience with one of three proposed design contractors. (Prior Projects and Experience Workbook)

For the VPC Dunes proposal, VPC provided a list of its experience and the experience of its contractors with designing substation projects. The list included 22 substation projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with 11 in California.

VPC indicated that the proposed design not only satisfies but exceeds the functional specification for the project. (QP-1)

For the VPC's Dunes proposal, VPC indicated that the proposed design not only satisfies but exceeds the functional specification for the project. VPC indicated that its proposal enhances the solution by adding a new 500 kV switching station for accessing an additional 1,622 MW of in-state geothermal, solar, and battery storage. (QP-1)

VPC indicated that the project has been under development for over ten years and has completed the WECC three phase rating process with the added requirement for peer review of all aspects of the local, regional, and NERC and WECC reliability criteria and planning standards. VPC also indicated that it has completed interconnection studies with APS and SDG&E as part of the wires-to-wires interconnection, confirming that the interconnection solutions for the project meet applicable reliability criteria. (QP-2) VPC indicated that potential risks to the project include reroutes to accommodate landowner concerns, reroute for three dairy farms, engineering to avoid a variance with DOT for the I-8 freeway, and missed or modified scope. (P-4)

VPC indicated potential project engineering risks include subsurface conditions, limited construction access, additional grounding, outages for crossing existing transmission lines not available when originally planned, and existing underground utilities or pipelines undiscovered. (P-5)

For the VPC's Dunes proposal, VPC provided the GPS coordinates for Dunes Switching Station, detailed design criteria, standards, description of the major electrical equipment, protection, relays, SCADA, and a representation that the site was recommended by BLM. VPC indicated that the diverse communication paths would be separate OPGW on the project 500 kV line. VPC indicated that it had completed 30% design of the Dunes 500 kV Switching Station, providing detailed engineering and design estimates as well as a full set of station layout and expansion drawings, and indicated that it has selected the location of the substation in consultation with the BLM. (S-1-S-8)

VPC provided detail design criteria for an 85 mile, 500 kV transmission line that included codes and standards and CPUC GO 95 and NESC requirements and routing criteria that included analysis of potential routes and options. VPC identified structure types, a two conductor bundle ACSR (aluminum conductor steel supported), span lengths of 1,300 to 1,500 feet, transmission line crossings, termination at existing substations, right-of-way width, and the ampacity for an ambient temperature of 50°C and total impedance. (T-1 to T-8) VPC indicated that it had performed advanced transmission line engineering work completing 60% of the detailed transmission line design. (C-4, A-4, QP-2)

3.8.11 ISO Comparative Analysis

Comparative Analysis of Technical (Environmental Permitting) Qualifications and Experience

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the qualifications and experience of both the project sponsor and its team members in obtaining and complying with environmental permits for a transmission project, including but not limited to (1) the permitting experience of the project sponsor and its team for projects it has developed, (2) the permitting experience for similar projects of the project sponsor's team member or members that have been designated as having responsibility for project permitting, and (3) how much of the experience of the project sponsor and its team is in the U.S. and in California.

U.S. environmental permitting laws, rules, regulations, and processes are unique to the U.S., and California environmental permitting laws, rules, regulations, and processes are unique to the state of California. For example, compliance with the California Environmental Quality Act (CEQA) is particularly unique to the state of California.

The ISO considers experience in the U.S. and California to be an advantage over experience in environmental permitting in other jurisdictions because a significant portion of the project will be located in California and there are special aspects of environmental regulation and processes in the U.S. and California for which experience is an advantage.

All five project sponsors' teams have experience permitting projects in the U.S. and in California, including experience with the environmental permitting process for transmission lines in California, although the amount of experience varied among the project sponsors and their proposed teams.

Regarding its analysis of this component of the factor, the ISO considers the environmental permitting teams identified by the project sponsors as part of their teams to be qualified and fully capable of handling the environmental permitting work associated with this project.

The ISO has determined that there is no material difference among CalGrid, Horizon West, Lotus, and VPC regarding their U.S. and California environmental permitting experience and that their U.S. and California experience is slightly better than LSPGC's U.S. and California experience.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the proposals of CalGrid, Horizon West, Lotus, and VPC and that their proposals are slightly better than LSPGC's proposal regarding this component of the factor due to LSPGC's limited California experience.

Comparative Analysis of Engineering Qualifications and Experience

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the qualifications and experience of both the project sponsor and its team members in engineering and designing transmission line and substation projects, including but not limited to (1) the engineering experience for similar projects of the project sponsor and its team member or members who have been designated as having responsibility for project engineering, and (2) how much of the experience of the project sponsor and its team is in the U.S. and in California.

The ISO considers experience in the U.S. and California to be an advantage over transmission line engineering and design experience in other countries because a significant portion of the project will be located in California and there are special aspects of engineering and design codes and regulations in the U.S. and California for which this experience is an advantage.

U.S. engineering and design codes and regulations are unique to the U.S., and California engineering and design laws, rules, regulations, and processes are unique to the state of California. For example, projects developed in the United States must adhere to the National Electrical Safety Code (NESC) published by the Institute of Electrical and Electronics Engineers (IEEE). In addition, the process that must be followed for engineering and design of transmission lines and substations in California includes adherence to requirements of the California Building Standards Commission, the California Energy Commission, the California Environmental Protection Agency, California Occupational Safety and Health Administration (OSHA), California High Voltage Electrical Safety Orders, California Building Code Title 24, and county and city planning and permitting requirements.

The ISO has considered the engineering and design qualifications and experience of the project sponsor and its team. The ISO considers the engineering team identified by CalGrid, Horizon West, Lotus, LSPGC, and VPC, for its two proposals, as part of their teams to be highly qualified and have substantial experience.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis of this component of the factor, the ISO has determined that there is no material difference among the proposals of CalGrid, Lotus, and VPC, for its two proposals, and that their proposals are better than Horizon West's proposal, which identified only one transmission line 200 kV or greater designed by its team in California in the past ten years, but which is better than LSPGC's proposal because the information provided by LSPGC indicated that neither it or its contractors has experience designing a 200 kV or greater transmission line in California over the past ten years.

Overall Comparative Analysis

The ISO considers the two components of this factor to be of roughly equal importance in the selection process for this project.

The ISO has determined that, regarding the first component of the factor (environmental permitting experience, including experience in California), there is no material difference among the proposals of CalGrid, Horizon West, Lotus, and the two VPC proposals and that their proposals are slightly better than LSPGC's proposal.

The ISO has determined that, regarding the second component (engineering experience), there is no material difference among the proposals of CalGrid, Lotus, and VPC, for its two proposals, and that their proposals are better than Horizon West's proposal, which is better than LSPGC's proposal.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the proposals of CalGrid, Lotus, and VPC, for its two proposals, and that their proposals are better than Horizon West's proposal, which is slightly better than LSPGC's proposal, regarding this factor overall.

3.9 Selection Factor 24.5.4(g): Previous Record Regarding Construction and Maintenance of Transmission Facilities

The seventh selection factor is "if applicable, the previous record regarding construction and maintenance of transmission facilities, including facilities outside the ISO Controlled Grid of the Project Sponsor and its team."

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) the previous record regarding construction including facilities outside the ISO controlled grid of the project sponsor and its team and (2) the previous record regarding maintenance including facilities outside the ISO controlled grid of the project sponsor and its team.

Construction Record

(Prior Projects and Experience Workbook; P-5, C-8)

3.9.1 <u>Information Provided by CalGrid</u>

CalGrid provided a list of its experience and the experience of its contractor with construction of transmission line projects. The list included 18 transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years and are located in the U.S., with two in California. CalGrid also indicated that it does not have any prior experience with its proposed construction contractor. (Prior Projects and Experience Workbook)

CalGrid provided a list of risks that its contractor has encountered when constructing transmission lines, which included access, landowner relations, federal and indigenous engagement, geotechnical and environmental issues, crossing water, and critical or threatened habitats. (P-5)

CalGrid indicated that neither it nor its construction contractor has had any safety, litigation, or environmental legal violations, fines, or other notices related to construction in the past ten years and is not under investigation or a defendant in any legal proceeding. (C-8)

3.9.2 Information Provided by Horizon West

Horizon West provided a list of its experience and the experience of its contractor with construction of transmission lines. The list included 34 transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with 25 in California. Horizon West also indicated that it has prior experience with one of its two proposed construction contractors. (Prior Projects and Experience Workbook)

Horizon West indicated that it has faced similar construction challenges and that its team and construction contractor have completed a number of projects in the same region. Horizon West indicated that it would draw on the vast experience of its parent company, gained through the successful execution of both transmission line and substation projects, and that the Horizon West project team will leverage lessons learned from recent projects to successfully execute and deliver the project. (P-5)

Horizon West indicated that neither it nor any of its affiliates has been subject to any violations or fines related to construction in the past ten years. (C-8)

3.9.3 Information Provided by Lotus

Lotus indicated that it has not yet chosen a construction contractor and submitted a list of four possible construction contractors along with experience of each of the contractors.

Lotus provided a list of its experience and the experience of its contractor with construction of transmission lines. The list included three transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with three in California. Lotus also indicated that it has prior experience with its construction contractor. (Prior Projects and Experience Workbook)

Lotus indicated that risks anticipated for construction are similar to the ones experienced in other southwest region transmission line projects where poor soil conditions affected access and foundation installation, requiring additional procedures to ensure excavation integrity, and that it is expected that similar conditions would be encountered where dunes are present. (P-5)

Lotus indicated that the construction subcontractor to a subsidiary of Lotus, and the approved project sponsor of the ISO competitively awarded Delaney-Colorado River 500 kV transmission line project, also known as Ten West Link, received four minor construction notices of violation and that no stop work notices were issued and Lotus took immediate action in response to these notices of violation to the acceptance of the CPUC. (C-8a) Lotus indicated that no additional violations or investigations have happened in the past ten years. (C-8b-C-8f)

3.9.4 Information Provided by LSPGC

LSPGC provided a list of its experience and the experience of its contractors with construction of transmission lines. The list included 15 transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with one in California. LSPGC also indicated that it has prior experience with one of its two proposed construction contractors. (Prior Projects and Experience Workbook)

LSPGC indicated that it has demonstrated experience successfully constructing projects with risks and challenges similar to those involved with constructing high-voltage transmission lines in remote arid environments similar to this project. LSPGC indicated that effective coordination would be required for the overcrossing of multiple transmission lines between 69 kV and 500 kV lines, Interstate 8, and termination at substations. (P-5)

LSPGC indicated that it has not been subject to any violations or fines in the past ten years related to construction but that a LSPGC affiliate, LSPGC Grid New York Corporation, received notices of violation from the New York Department of Public Service. LSPGC indicated that it has not been subject to any fines or investigation in the past ten years. (C-8b-C8f)

3.9.5 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC provided a list of its experience and the experience of its contractors with construction of transmission lines. The list included 19 transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with four in California. VPC also indicated that it does not have prior experience with its proposed construction contractor. (Prior Projects and Experience Workbook)

For the VPC Dunes proposal, VPC provided a list of its experience and the experience of its contractors with construction of substations. The list included 10 substation construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with seven in California. (Prior Projects and Experience Workbook)

VPC indicated that the project team has completed the construction of many large transmission lines and substation projects and that many of these projects have been located within the proposed project area and similar terrains.

VPC indicated risks that included endangered species, landowner concerns, archaeological discoveries, noxious weeds, storm water management, grounding, clearances, and existing underground utilities. (P-5)

VPC indicated that no construction-related law violations have occurred within the past ten years. (C-8)

Maintenance Record

(Prior Projects and Experience Workbook; P-5, M-4, M-5, M-6, M-7)

3.9.6 Information Provided by CalGrid

CalGrid provided a list of its experience and the experience of its contractors with the maintenance of transmission lines. The list included 11 transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years and are located in the U.S., with three in California. (Prior Projects and Experience Workbook)

CalGrid indicated that its O&M contractor has a successful record of providing operations and maintenance services to 15 transmission line projects in 12 states in the U.S., totaling more than 200 miles of line. CalGrid indicated that its O&M contractor's experience includes overhead and underground transmission lines, submarine cables, DC transmission cables, substations, and converter stations. (M-4)

CalGrid indicated that its management personally led the development and implementation of wildfire mitigation plans in California and would do the same for CalGrid. (M-5)

CalGrid indicated that as a recently formed entity, it does not currently have historical audit reports for maintenance of facilities. However, CalGrid provided the inspection reports from its O&M contractor performed for third parties that covered maintenance activities such as condition of tower, foundation, and ground straps, condition of conductors and hardware, including spacers, insulators and splices, vegetation, and other threats. These reports indicated that no anomalies were observed and that no vegetation was encroaching on the transmission line and concluded that the power lines appear to be in good condition with no loose or failing hardware. The reports included additional information on vegetation management.

CalGrid listed facilities for which its team members have been responsible for maintenance. (M-6)

CalGrid indicated that its O&M subcontractor regularly reports on availability measures for transmission systems under its management and is capable of capturing the necessary information to report on availability measures as described in Transmission Control Agreement (TCA) Appendix C Section 4.3. (M-7)

CalGrid indicated that it has encountered a number of operations and maintenance challenges that are comparable to the risks and challenges posed by the project, including wildfire risk, environmental impact, access challenges, and weather challenges. (P-5)

3.9.7 Information Provided by Horizon West

Horizon West provided a list of its experience and the experience of its contractors with the maintenance of transmission lines. The list included 59 transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years, and are located in the U.S., with six in California. (Prior Projects and Experience Workbook)

Horizon West indicated that it is an ISO PTO and has experience with transmission line and substation maintenance practices that are consistent with the ISO transmission maintenance standards and that have been approved by the ISO. (M-4)

Horizon West indicated that with its ability to rely on the combined experience of three ISO PTOs (Horizon West, GridLiance, and Trans Bay Cable) and its affiliate, Florida Power & Light Company, Horizon West has the capability to update its substation and transmission line maintenance practices as it pertains to the proposed project's equipment. (M-4) Horizon West indicated that NextEra would provide vegetation management services and that it has experience managing vegetation alongside over

80,000 miles of power lines and has done so for about the past one hundred years. (M-5)

Horizon West indicated that its vegetation management team has experience managing transmission lines in similar rural and weather conditions for other NextEra projects in California. (M-5)

Horizon West provided the annual maintenance audit reports of Horizon West's maintenance practices by the ISO for the years 2012 through 2022, which showed generally good compliance with Horizon West and Trans Bay Cable standards.

Horizon West also provided a document describing experience creating and reporting wildfire mitigation plans. (M-6)

Horizon West indicated that it has experience providing the ISO with availability measures in accordance with TCA Appendix C. Horizon West indicated that its procedures describe how it would track operational performance and availability of facilities to adequately report the facilities' performance to the ISO and other stakeholders. Horizon West provided copies of monitoring procedures and reports. (M-7)

Horizon West indicated that it has faced maintenance-related risks and challenges similar to those foreseen for the project, such as vegetation management and maintenance of underground cables, and provided several examples of projects where it had faced similar risks and challenges. (P-5)

3.9.8 Information Provided by Lotus

Lotus provided a list of its experience and the experience of its contractors with the maintenance of transmission lines. The list included two transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years, and are located in the U.S., with none in California. (Prior Projects and Experience Workbook)

Lotus indicated that its O&M contractor has a successful record of providing operations and maintenance services to 15 transmission line projects in 12 states in the U.S., totaling more than 200 miles of line, and tying in more than 10,000 MW of energy. (M-4)

Lotus indicated that in order to ensure compliance with its own standards, its O&M contractor performs assessments on its facilities on a three-year basis in which every program and procedure (including operations, maintenance, and NERC) is assessed to ensure compliance. (M-6)

Lotus also provided an annual inspection report, performed by a third party, at a substation operated and maintained by its O&M contractor. The report noted some discrepancies and recommended corrective actions. (M-6)

Lotus provided an annual transmission line and structure report for a line operated and maintained by its O&M contractor. The report covered 56 transmission structures and included both visual and thermal evaluations. (M-6)

Lotus indicated that its O&M contractor regularly reports on availability measures as described in TCA Appendix C Section 4.3 for its clients. (M-7)

Lotus indicated that it has faced maintenance-related risks and challenges similar to those foreseen for the project, such as wildfire risk, environmental impact, access, and weather challenges and provided specific examples of a project in California and two other projects where it had faced maintenance-related risks and challenges. (P-5)

3.9.9 Information Provided by LSPGC

LSPGC provided a list of its experience and the experience of its contractors with the maintenance of transmission lines. The list included five transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years, and are located in the U.S., with none in California. (Prior Projects and Experience Workbook)

LSPGC indicated that a recent maintenance report submitted to the ISO by DesertLink tabulated maintenance and inspection tasks and indicated the number of planned and actual occurrences. The report indicated that in all cases the actual number equaled or exceeded the planned number.

LSPGC provided a sample vegetation management inspection report that covered the inspection of six transmission lines in Texas and identified no vegetation related outages.

LSPGC provided a five-year maintenance report that covered a maintenance outage on a transmission line and described the work performed, the findings, and corrective actions taken. (M-6)

LSPGC indicated that it currently complies with the requirements of TCA Appendix C Section 4.3 and provided DesertLink's 2022 Availability Measures report, which indicated a 100% availability.

LSPGC provided a summary of availability data for all LS Power grid transmission facilities, which indicated that the availability data tabulated considers only forced outages. The data indicated that LS Power's availability ranged from 99.43% to 100% over the period 2018 to 2022. LSPGC indicated that LS Power represented that the lowest number was caused by a major ice storm that affected the area. (M-7)

LSPGC indicated that it has faced operations and maintenance-related risks and challenges similar to those foreseen for the project that includes operating and maintaining a line in a desert environment and provided specific example of a project in Texas where it faced similar challenges. (P-5)

3.9.10 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC provided a list of its experience and the experience of its contractors with the maintenance of transmission lines. The list included 12 transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years, and are located in the U.S., with six in California. (Prior Projects and Experience Workbook)

For the VPC Dunes proposal, VPC provided a list of its experience and the experience of its contractors with the maintenance of substations. The list included 13 substation projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with ten in California. (Prior Projects and Experience Workbook)

VPC indicated that it and its parent Grid United do not have any operating facilities at this time; however, members of the project sponsor's team, including its third-party O&M provider have extensive compliance experience.

VPC indicated that its O&M contractor's compliance experience with standards for inspection, maintenance, repair, and replacement of similar facilities include proven programs and scalable processes.

VPC provided compliance reports from its O&M contractor for work performed for third parties for transmission and distribution facilities within the ISO footprint that indicated that no anomalies were observed and that no vegetation was encroaching on the transmission line and concluded that the power lines appear to be in good condition with no loose or failing hardware. (M-6)

VPC indicated that its O&M contractor regularly reports on Availability Measures as described in TCA Appendix C Section 4.3 for its clients. (M-7)

VPC indicated that it has faced operations and maintenance risks similar to those foreseen for the proposed project and provided several examples, including noxious weed management, timeframe for post-construction reclamation, and limited construction access. (P-5)

3.9.11 <u>ISO Comparative Analysis</u>

Comparative Analysis of Construction Record

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the record and experience of both the project sponsor and its team members in constructing transmission line projects, and how much of the experience of the project sponsor and its team is in the U.S. and in California. The ISO considers experience in the U.S. and California to be an advantage over transmission line construction experience in other jurisdictions because a significant portion of the project will be located in California and there are special aspects of construction codes and regulations in the U.S. and California for which this experience is an advantage.

U.S. construction laws, rules, regulations, and processes are unique to the U.S., and California construction laws, rules, regulations, and processes are unique to the state of California. For example, the process that must be followed in California includes adherence to requirements of Cal OSHA, the California Air Resources Board, the California Office of Historic Preservation, Title 22 regarding hazardous waste, and city and county codes. U.S. laws, rules, regulations, and processes applicable to construction include federal OSHA, NEPA, Storm Water Pollution Prevention Plan, and U.S. Fish and Wildlife Service requirements, Fair Labor Standards Act regulations, and National Electric Code standards.

The ISO has considered the construction qualifications and experience of the project sponsors and their teams. Regarding its analysis of this component of the factor, the ISO considers the construction contractors identified by CalGrid, Horizon West, Lotus, LSPGC, and VPC as part of their teams to be qualified, experienced, and capable of handling the construction work associated with this project. Although the number of transmission facilities constructed varies among the project sponsors' proposed teams, all five project sponsors' teams have established experience in the construction of transmission line projects in the U.S. and California.

Based on the foregoing considerations, and considering the specific nature and scope of the construction involved with this project, in conjunction with all the other considerations included in the ISO's analysis of project sponsor and contractor construction qualifications and experience, the ISO has determined that there is no material difference among the proposals of CalGrid, Horizon West, Lotus, LSPGC, and VPC regarding this component of the factor.

Comparative Analysis of Maintenance Record

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the record and experience of both the project sponsor and its team members in maintaining transmission projects, including but not limited to experience with compliance with NERC standards.

The ISO has determined that all of the project sponsors and their proposed teams have demonstrated the basic capability to manage the maintenance of the project; however, the amount of past experience with extra high voltage (EHV) transmission facilities varies among the project sponsors and their proposed teams.

The ISO has determined that the proposal of Horizon West demonstrated significantly more experience in maintaining EHV transmission lines than the proposals of the other project sponsors. The ISO also determined that the proposals of CalGrid and VPC demonstrated more experience in maintaining EHV transmission lines than the proposals of Lotus and LSPGC.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, the proposal of Horizon West is slightly better than the proposals of CalGrid and VPC, among which there is no material difference, which are slightly better than the proposals of Lotus, and LSPGC, between which there is no material difference.

Overall Comparative Analysis

The ISO considers the two components of this factor to be of roughly equal importance in the selection process for this project.

Regarding the first component of the factor (previous record regarding construction of transmission facilities), the ISO has determined that there is no material difference among the proposals of CalGrid, Horizon West, Lotus, LSPGC, and VPC regarding this component of the factor.

Regarding the second component of the factor (previous record regarding maintenance), the ISO has determined that the proposal of Horizon West is slightly better than the proposals of CalGrid and VPC, among which there is no material difference, which are slightly better than the proposals of Lotus and LSPGC, between which there is no material difference, regarding this component of the factor.

Based on the combination of the ISO's analyses of the two components of this factor, the ISO has determined that the proposal of Horizon West is slightly better than the proposals of CalGrid and VPC, among which there is no material difference, which are slightly better than the proposals of Lotus and LSPGC, between which there is no material difference, regarding this factor overall.

3.10 Selection Factor 24.5.4(h): Adherence to Standardized Construction, Maintenance, and Operating Practices

The eighth selection factor is "demonstrated capability to adhere to standardized construction, maintenance and operating practices of the Project Sponsor and its team."

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the three components of this factor separately and then combined them into an overall comparative analysis for this factor. The three components are:
(1) demonstrated capability to adhere to standardized construction practices,
(2) demonstrated capability to adhere to standardized maintenance practices, and
(3) demonstrated capability to adhere to standardized operating practices.

Construction Practices

(P-5, C-1, C-2, C-3, C-4, C-5, C-6, C-7, C-8)

3.10.1 Information Provided by CalGrid

CalGrid identified common construction risks and challenges that its construction contractor has encountered when constructing transmission lines, which included access work complications, landowner relations, federal and indigenous engagement, geotechnical and environmental issues, and critical (threatened or endangered) species habitats or railroads. (P-5)

CalGrid indicated that it has selected a construction contractor and that its contractor would develop inspection and test plans. CalGrid also indicated that the construction contractor uses a detailed process for receiving and inspecting materials and equipment delivered to the project and identified five primary laydown areas. (C-1, C-2)

CalGrid indicated that it does not anticipate clearances being required to cross transmission lines. (C-3)

CalGrid indicated that a multi-disciplinary team would complete constructability reviews. CalGrid indicated that constructability planning would also include procurement strategies, construction execution, and periodic drawing and specification reviews. (C-4)

CalGrid indicated that it does not currently possess any easements, orders of possession, or permits for the project. (C-5)

CalGrid indicated that it uses Primavera P6 software to develop a project schedule using the critical path method and that the schedule includes all project milestones and is structured so that it can be rolled up and presented at various levels of detail, and includes all aspects of the project. (C-6)

CalGrid indicated that it does not anticipate the need for any unique or special construction techniques for the construction of the project.

CalGrid indicated a key aspect of project construction would involve wildfire prevention and mitigation. (C-7)

CalGrid indicated that each construction crew would be staffed with one team member who would be solely responsible for wildfire detection and mitigation. (C-7)

3.10.2 <u>Information Provided by Horizon West</u>

Horizon West indicated that construction would be in high-heat temperature areas and remote locations and that it would hire adequate help to relieve others during high-heat temperatures. Horizon West indicated that it is sensitive to the presence of valley fever and to mitigate its impacts and ensure the safety of personnel, a site assessment would be completed prior to construction. (P-5)

Horizon West indicated that its construction management and inspection team would be active through all phases of construction and the engineer(s) of record would perform site visits, inspections, walk-downs, and witnessing of tests prior to energization. (C-1)

Horizon West indicated that it would establish material laydown yards close to the project and these yards are anticipated to be approximately five to six acres in size and would be fenced, screened, and staffed with full-time, on-site security personnel. (C-2)

Horizon West indicated that it would develop a plan to establish a procedure required for outages, as well as the necessary steps required to restore the equipment to service. (C-3)

Horizon West indicated that it would coordinate design and constructability reviews and these reviews would encompass all aspects of the design. (C-4)

Horizon West indicated it has not secured any easements. (C-5)

Horizon West indicated that it would use Primavera P6 for the project schedule and that the project manager and construction superintendent would have overall responsibility and oversight of the project schedule. (C-6)

Horizon West indicated that standard construction techniques would be used for the project. (C-7)

3.10.3 <u>Information Provided by Lotus</u>

Lotus indicated that risks for construction are similar to the ones experienced on the Ten West Link and other southwest region transmission line projects and that poor soil conditions affected access and foundation installation, requiring additional procedures to ensure excavation integrity, and that it is expected that similar conditions would be encountered where dunes are present. (P-5)

Lotus indicated that its quality control manager would conduct daily field inspections of the construction operations, including those by subcontractors, and perform tests on materials for self-performed work and indicated that construction yards would be identified and sized for multiple uses. (C-1, C-2)

Lotus indicated that it would coordinate with the ISO and impacted utility operations and management teams regarding all outages, crossings, and tie-ins to existing stations. (C-3)

Lotus indicated that constructability reviews would be completed at 30%, 60%, 90%, and issue for construction milestones. (C-4)

Lotus indicated that it does not currently possess any easement. (C-5)

Lotus indicated that project sequencing would rely on build-up of project activities so that it would not need unique lags or constraints and throughout the progression of the project the project manager would maintain and update the schedule regularly. (C-6)

Lotus indicated that a helicopter would be used for wire pulling operations. (C-7)

3.10.4 Information Provided by LSPGC

LSPGC indicated that it has demonstrated experience successfully constructing projects with risks and challenges similar to those involved with constructing high-voltage transmission lines in remote arid environments similar to this project. LSPGC indicated that effective coordination would be required for the overcrossing of multiple transmission lines between 69 kV and 500 kV lines, Interstate 8, and termination at substations. (P-5)

LSPGC indicated that it has assembled a skilled and experienced team to complete and oversee construction activities for the project and that the quality assurance and quality control plan would detail the inspection program and provided a detailed list of the items to be inspected. (C-1)

LSPGC indicated that it would directly purchase the major material for the transmission line and would establish three material yards to support construction of the project and that LSPGC would coordinate with impacted transmission owners with the negotiation of interconnection and crossing agreements. (C-2, C-3)

LSPGC indicated that it has completed advanced design of the project and that all designs and specifications go through a rigorous series of quality assurance and quality control checks before being implemented on the project. (C-4)

LSPGC indicated that it has completed a routing study, consultation with regulatory and permitting agencies, identification of all rights-of-way and land rights necessary to implement the project, detailed engineering, and a detailed implementation schedule. (C-4) LSPGC indicated that its general construction contractor would prepare and maintain a detailed "P6" schedule and that LSPGC would then incorporate this information into the master project schedule and these would be reviewed during the kick-off, weekly, and monthly meetings. (C-6)

LSPGC indicated that it does not anticipate the use of unique construction techniques for this project. (C-7)

LSPGC indicated it would require its construction contractor to establish fire prevention measures in a construction fire prevention plan as part of the site-specific safety plan. (Response to qualification questions re Question Matrix questions 34 & 35)

3.10.5 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC indicated that its project team has completed the construction of many large transmission lines and substation projects and that many of these projects have been located within the proposed project area and similar terrains. VPC indicated risks that included endangered species, landowner concerns, archaeological discoveries, noxious weeds, storm water management, grounding, clearances, and existing underground utilities. (P-5)

VPC indicated that it would negotiate with its construction contractor to perform periodic inspection during construction, including during critical activities, and that inspections would include factory, access road, foundations, structures, and wire installation. (C-1)

VPC indicated that two material yard locations would be identified and that it would work with IID to use their existing material laydown yards. (C-2)

VPC indicated that transmission operators and the ISO would be contacted for the purpose of coordinating any required outages. (C-3)

VPC indicated that it has completed a preliminary constructability review on completion of the 60% design and would complete a structure-by-structure desktop review of the project with a final constructability review to be completed after receipt of all approvals. (C-4)

VPC indicated that it does not have any existing rights-of-way and that mitigation measures and permit conditions would be identified in the project's final plan of development that would be filed with the BLM. (C-5)

VPC indicated that its approach to construction schedule development would be based on past project experience, utilization of subject matter experts, and input from contractors and suppliers and that its construction contractor has developed a project construction schedule for the project. (C-6)

VPC indicated limited water resources, extreme weather, environmental sensitivities, and access as challenges to construction and provided mitigation. (C-7)

Maintenance Practices

CC-3, CC-4, CC-5, M-1 through M-10)

3.10.6 Information Provided by CalGrid

CalGrid provided a list of maintenance activities proposed by its O&M contractor, as well as the frequency of those activities, such as monthly, semi-annually, or annually. This list included transmission tower and line maintenance, surge arrestor maintenance, conductors, optical ground/static/shield/ ground wires, and associated hardware maintenance, and vegetation management. (CC-3)

CalGrid indicated that one employee would be assigned to oversee the O&M contractor. (CC-4)

Regarding the number of contractor personnel assigned for maintenance, CalGrid estimated four to six full time employees (FTEs). (CC-5)

CalGrid provided a copy of the signed memorandum of understanding between it and its O&M contractor and indicated that it would enter into a maintenance services agreement with this contractor.

CalGrid indicated that it has encountered a number of operations and maintenance challenges that are comparable to the risks and challenges posed by the project, including wildfire risk, environmental impact, access challenges, and weather challenges. (P-5)

CalGrid indicated that its O&M contractor's training program encompasses all aspects of training, including management, operations, maintenance, environmental considerations, safety programs, and administration, to ensure that it has qualified, skilled, and experienced O&M personnel assigned to the transmission project. (O-3)

CalGrid described how anticipated maintenance responsibilities would be divided among itself, its O&M contractor, and other subcontractors. (M-1)

CalGrid indicated that it would utilize subcontractors through its O&M contractor for maintenance work.

CalGrid indicated that it and its O&M contractor would work with subcontractors to ensure that only appropriately skilled and credentialed individuals would perform their respective tasks and described the skills required for field personnel. (M-2)

CalGrid indicated that its O&M contractor would administer training for maintenance personnel based on training programs successfully used at other facilities operated by it. CalGrid indicated that the O&M contractor training program encompasses all aspects of training, including management, operations, maintenance, environmental considerations, safety programs, and administration. (M-3)

CalGrid indicated that the maintenance program of its O&M contractor for transmission line projects includes all of the elements listed in TCA Appendix C Sections 5.2.1 (Transmission Line Circuit Maintenance) and 5.2.2 (Station Maintenance). (M-4)

CalGrid indicated that the O&M contractor's vegetation management plan complies with the National Electric Safety Code, ANSI A300 Part 7: American Operations Integrated Vegetation Management and Electric Utility Rights-of-Way, and the ISA best management practices. CalGrid indicated that the project would comply with vegetation management standards required by the NERC and WECC vegetation management guidelines. (M-5)

CalGrid indicated that as a recently formed entity, it does not currently have historical audit reports for maintenance of facilities. CalGrid indicated that its O&M contractor has provided five years of examples of third-party inspection reports for a 230-kV line in California against industry standards implemented for an existing confidential client with no anomalies observed. (M-6)

CalGrid indicated that its O&M contractor regularly reports on availability measures for transmission systems under its management. CalGrid indicated that its current system is capable of capturing the necessary information to report on availability measures as described in TCA Appendix C Section 4.3. (M-7)

CalGrid indicated that it does not anticipate any exceptions to the TCA to integrate the project into the ISO controlled grid. (M-8)

CalGrid indicated that its team is experienced in coordinating outages for scheduled and unscheduled maintenance with the ISO and non-participating generators and described the steps that it would take to ensure compliance with TCA Section 7. (M-9)

CalGrid indicated that its O&M contractor plans to subcontract maintenance for the project to a qualified maintenance provider in the same locale as the project, which would allow for a quick response to any issues that may arise.

CalGrid indicated that within four hours of an event occurring, on-call local response personnel would be on-site to perform in-person assessment of an event and within four to eight hours repair crews, equipment, and material would be on-site for live-line or typical corrective repairs. CalGrid also estimated that repairs for small-scale emergency events would be completed within 48 hours and large-scale events within 72 hours of an event. (M-10)

CalGrid indicated that its O&M contractor is currently in the process of finalizing selection of a contractor for emergency maintenance services. CalGrid indicated that its O&M contractor has consulted with this subcontractor to develop the emergency response times for the project.

CalGrid indicated that it would seek to join the Western Region Mutual Assistance group, which provides mutual aid to its members in the event restoration is needed. (O-13

CalGrid indicated that an emergency response and spare equipment program is being evaluated and discussions are underway on how to maximize the ability to respond to such events, including the use of the O&M contractor and other providers to maximize ability to respond, minimize costs, and provide these services in accordance with good utility practice.

CalGrid indicated that for hardware and insulators, its construction contractor would procure and hold a small percentage (2-3%) of construction spares for loss and breakage during construction and would transfer any unused spares to CalGrid and the O&M contractor to have at project startup. (O-15)

CalGrid indicated that during commercial operations its O&M contractor would carry an inventory stock of 1-3% for hardware and insulators as O&M spares for use when damage or issues are noted during inspections in accordance with prudent utility practice. (O-15)

CalGrid indicated that it would adhere to industry leading programs, processes, and operations procedures that would be documented in a CPUC-ratified wildfire mitigation plan. CalGrid provided an outline of its envisioned plans for mitigation and operations under extreme conditions for facilities in High Fire Threat Districts. (Attachment G1_1 Wildfire Plans and Procedures)

3.10.7 Information Provided by Horizon West

Horizon West indicated that it has experience in accordance with the ISO maintenance procedures.

Horizon West provided the frequency of its proposed transmission line maintenance activities, such as maintenance associated with rights-of-way, vegetation management, foundations, structures, bonding, and grounding, guys, and anchors, among others. (CC-3)

Horizon West indicated that three FTEs would be required for performing O&M functions and provided additional information on the number of FTEs that would be used for various O&M job categories and their estimated utilization. (CC-4)

Horizon West indicated it plans to supplement its O&M capability as needed with services from an O&M contractor. (CC-5)

Horizon West indicated that the project's maintenance operations would be undertaken by its field operations team and that the maintenance base would be at the existing Horizon West Suncrest SVC facility in Alpine, California. Horizon West indicated that its affiliates, which have experience maintaining transmission assets under the ISO, would provide maintenance support services such as vegetation management and compliance, maintenance audit, inspection reviews, safety, security, wildfire and environmental management, land management, and maintenance compliance. (M-1)

Horizon West listed certifications and experience requirements for the personnel who undertake maintenance activities. Horizon West indicated that its maintenance and emergency support vendor has agreed to provide qualified maintenance personnel, tools, and equipment as necessary to assist in substation, line, and protection maintenance. Horizon West described the training and qualification requirements of various of its emergency support vendor's engineers, technical specialists, line foremen, linemen, and apprentice linemen. (M-2)

Horizon West indicated that it has a rigorous system maintenance personnel training program and continued education requirement. (M-3)

Horizon West indicated that it is an ISO PTO and has transmission line and substation maintenance practices that are consistent with the ISO transmission maintenance standards, which have been approved by the ISO. (M-4)

Horizon West indicated that its field maintenance team members have experience addressing a wide variety of operating challenges, ranging from wildfires, seismic, hurricanes, tornadoes, and other high wind conditions to dust contamination, avian interaction, and lightning. (M-4)

Horizon West indicated that NextEra would provide vegetation management services. Horizon West indicated that NextEra manages vegetation alongside over 80,000 miles of power lines and has done so for about the past one hundred years.

Horizon West indicated that its vegetation management team manages lines in similar rural and weather conditions for other NextEra projects in California. (M-5)

Horizon West indicated that its vegetation management procedures address wildfire precautions and landowner-controlled field-burning requirements. Horizon West indicated it has a California wildfire mitigation plan filed with the CPUC. (M-5)

Horizon West provided the annual maintenance audit reports of its maintenance practices by the ISO for the years 2012 through 2022, which showed generally good compliance with Horizon West and Trans Bay Cable standards.

Horizon West also provided a document describing experience creating and reporting wildfire mitigation plans. (M-6)

Horizon West indicated that it has experience providing the ISO with availability measures in accordance with TCA Appendix C 4.3 and the ISO maintenance procedures. Horizon West indicated that its procedures describe how it would track operational performance and availability of facilities to adequately report the facilities' performance to the ISO and other stakeholders. Horizon West provided copies of monitoring procedures and reports. (M-7)

Horizon West indicated that adding the project to the ISO controlled grid is not expected to require any changes or exceptions to the provisions of the TCA. (M-8)

Horizon West indicated that it is an ISO PTO operating in accordance with TCA Section 7. (M-9)

Horizon West indicated that it and its affiliates have a team of approximately 150 technical staff in California and that over a third of this team are located within a 90-minute drive from the project. Horizon West further indicated that the project maintenance team would have two dedicated staff based in the project vicinity. (M-10)

Horizon West indicated that it and its affiliates have experience in and are capable of establishing and managing their own standards of inspection, maintenance, repair, replacement, and maintaining the rating and technical performance of its facilities in accordance with the ISO applicable reliability criteria and the performance standards established under Section 14 of the TCA. (O-12)

Horizon West indicated that it is fully capable of managing emergencies and fulfilling its obligations for system emergency reports under TCA Section 9.2 and 9.3. Horizon West indicated that it is a signatory to the ISO TCA in connection with the Suncrest SVC Project and has operated that project in compliance with the responsibilities of TCA Section 9.2 and 9.3 requirements.

Horizon West also provided information on NextEra's corporate emergency management plan framework for organizational readiness for threats and hazards. (O-13)

Horizon West indicated that it would maintain a spare stock of critical transmission line components, hardware, wire, and structures to ensure expedient recovery in the event of an emergency.

Horizon West indicated that it would use the NextEra integrated supply chain computerized spares asset management program that manages the spares stock and restocking, oversees the spares holding location, and dispatches spare parts for delivery within hours.

Horizon West indicated that in addition to spares on-site, it would have access to its affiliate-wide spares sharing program, specifically Florida Power & Light Company spares, and strategic support of equipment suppliers. (O-15)

Horizon West indicted it has a CPUC-approved wildfire mitigation plan and maintains active fire-prevention programs. Horizon West indicated it would extend its wildfire mitigation plan to include the new project.

Horizon West indicated it employs a wildfire prediction and tracking program that would be extended to include the project's assets. (O-13)

3.10.8 Information Provided by Lotus

Lotus provided a list of transmission line maintenance activities, which included maintenance related to conductor and shield wire, pole-top switches, structure grounds, guys, and anchors, insulators, and vegetation management, among others. (CC-3)

Lotus indicated that it would utilize its existing in-house asset management team consisting of five FTEs to oversee the O&M contractor. (CC-4)

Regarding the number of contractor personnel assigned for maintenance, Lotus estimated four to six FTEs. (CC-5)

Lotus indicated that it has extensive experience working with its O&M contractor to provide O&M services for several of its power generation projects. Lotus indicated that the same O&M contractor is providing O&M services for its Ten West Link and Cielo Azul projects.

Lotus indicated that it and its O&M contractor and specialty subcontractors as necessary would work together to execute the planned and unplanned maintenance plan for the project. (M-1)

Lotus indicated that its O&M contractor would be responsible for hiring maintenance personnel for the project and described the qualification and experience requirements for the O&M contractor's project manager and field personnel. (M-2)

Lotus indicated that its O&M contractor would administer training for maintenance personnel based on training programs successfully used at other facilities that it operates. (M-3)

Lotus indicated that for maintenance work that is subcontracted, its O&M contractor would ensure and verify that the maintenance company is properly qualified, and its employees are trained and certified to conduct transmission line, substation, or vegetation management maintenance. (M-3)

Lotus indicated that the maintenance program of its O&M contractor for transmission line projects includes all the elements listed in TCA Appendix C Sections 5.2.1 (Transmission Line Circuit Maintenance) and 5.2.2 (Station Maintenance). (M-4)

Lotus indicated that in accordance with the vegetation management procedure of its O&M contractor, vegetation management would be conducted on a 5-year cycle, with 20 percent of the transmission project being completed every year. (M-5)

Lotus indicated that its O&M contractor's vegetation management plan complies with the National Electric Safety Code, American National Standards Institute (ANSI) A300 Part 7: American Operations Integrated Vegetation Management and Electric Utility rights-of-way, and the International Society of Arboriculture best management practices. Additionally, the project sponsor would comply with vegetation management standards required by the NERC and WECC vegetation management guidelines. (M-5)

Lotus indicated that its O&M contractor regularly reports on availability measures for its clients and can capture the necessary information to report on availability measures as described in TCA Appendix C Section 4.3. (M-7)

Lotus indicated that it does not anticipate any exceptions to the TCA to integrate the project into the ISO controlled grid. (M-8)

Lotus indicated that its team is experienced in coordinating outages for scheduled and unscheduled maintenance with the ISO and non-participating generators. (M-9)

Lotus indicated that its O&M contractor plans to subcontract maintenance for the project with a qualified maintenance provider in the same locale as the project, as well as hire a project manager who would be located near the project. (M-10)

Lotus estimated that within two hours of an event occurring, on-call local response field maintenance personnel would be on-site and corrective repairs and necessary O&M actions would begin within 24 hours and repairs would be completed within 72 hours for small-scale events and within 96 hours for large-scale events. (M-10, O-13)

Lotus also identified the resources available to respond to major problems, including its O&M contractor's project manager and subcontractor's maintenance team. (O-13

Lotus indicated that for hardware and insulators, its construction contractor would procure and its O&M contractor would carry a small percentage of construction spares for loss and breakage during construction. Lotus indicated that during commercial operations, its O&M contractor would plan to carry an inventory stock of one to three percent for hardware and insulators as O&M spares for use when damage or issues are noted during inspections. (O-15)

Lotus indicated that the project would be required to have a wildfire mitigation plan and its O&M contractor would implement and develop emergency protocols for extreme conditions and emergency events as part of this plan. (P-5)

3.10.9 Information Provided by LSPGC

LSPGC provided a maintenance plan for transmission lines and substations. LSPGC also provided a detailed list of transmission line and substation maintenance tasks along with their frequencies. (CC-3)

LSPGC indicated that the number of FTEs for maintenance activities would be 3.8. (CC-4)

LSPGC indicated that it estimates approximately 0.7 FTEs on an annualized basis to conduct the contracted maintenance activities. (CC-5)

LSPGC indicated that it would be responsible for completing all maintenance activities for the project. LSPGC indicated that internal personnel would perform planned and routine inspection and maintenance activities and third-party contractors would be utilized for unplanned, larger scope, or specialized maintenance activities.

LSPGC indicated that it would hire one field technician to be located in close proximity to the project to perform transmission line inspections and oversee the outside contractors for the project. LSPGC indicated that it would also be able to leverage five additional technicians located in California to support maintenance of other LSPGC projects.

LSPGC indicated that it has identified two outside contractors to conduct preventative and predictive maintenance, support forced outage response, perform emergency repairs, and complete major facility rebuilds.

LSPGC indicated that one of its O&M contractors has over 200 qualified employees in its California offices and that the other contractor has three California offices. (M-1)

LSPGC indicated that it employs highly qualified and experienced field personnel.

LSPGC indicated that it assesses all contractors to ensure their personnel have the appropriate training and expertise for the work before authorizing any work order.

LSPGC described the responsibilities and experience requirements for field and substation technicians. (M-2)

LSPGC indicated that all vegetation management personnel are required to complete and maintain annual training necessary to be certified vegetation management technicians. (M-3)

LSPGC indicated that it would comply with the provisions of TCA Appendix C Sections 5.2.1 and 5.2.2 through its existing maintenance policies and procedures and by leveraging the experience of its affiliate, DesertLink, which currently complies with these provisions.

LSPGC indicated that DesertLink's transmission maintenance and inspection plan was approved by the ISO in 2020.

LSPGC indicated that its maintenance and testing procedures are based upon manufacturers' recommendations, national standards, good utility practice, and NERC guidance documents. (M-4)

LSPGC indicated that the project would be integrated into its transmission vegetation management plan based on experience maintaining hundreds of miles of 230 kV, 345 kV, and 500 kV transmission lines across multiple regions. (M-5)

LSPGC indicated that rights-of-way vegetation management would be conducted by the vegetation management contractors. This would consist of herbicide spraying (where permitted) to remove undesired species and inhibit grown, rights-of-way mowing, rights-of-way side cutting, removal of encroaching trees, and vegetation removal to mitigate wildfire risks.

LSPGC indicated that it would have a wildfire mitigation plan to govern the construction, maintenance, and operations of its facilities to minimize the risk of catastrophic wildfire. LSPGC indicated that it would also formalize an emergency preparedness plan for the project. (M-5)

LSPGC indicated that it currently complies with the ISO standards for inspection, maintenance, repair, and replacement set forth in TCA Appendix C.

LSPGC indicated that a recent maintenance report submitted to the ISO by DesertLink tabulated maintenance and inspection tasks and indicated the number of planned and actual occurrences. The report indicated that in all cases the actual number equaled or exceeded the planned number.

LSPGC provided a five-year maintenance report, which covered a maintenance outage on a transmission line and described the work performed, the findings, and corrective actions taken. (M-6)

LSPGC provided DesertLink's 2022 availability measures report, which indicated a 100% availability.

LSPGC also provided a summary of availability data for all LS Power transmission facilities, where the availability ranged from 99.43% to 100% over the period 2018 to 2022. LSPGC indicated that LS Power represented that the lowest number was caused by a major ice storm that affected the area. (M-7)

LSPGC indicated that it believes the addition of the project to the ISO controlled grid would require an amendment to TCA Appendix A to identify the project as under ISO control. (M-8)

LSPGC indicated that it currently performs planned outage coordination for the transmission lines, substations, and associated facilities it operates.

LSPGC indicated that it would be responsible for responding to all forced outages on the project. LSPGC indicated that the project would be incorporated into LSPGC's emergency operations plan and emergency response plan. (M-9)

LSPGC indicated that one technician would be stationed in the project area to perform routine maintenance and inspections and oversee the outside contractors for the project. LSPGC indicated that it would also have five technicians located near the Fresno and San Francisco Bay areas to support the project as needed.

LSPGC indicated that its technician located in the project area would be able to respond to all parts of the project within two hours. LSPGC indicated that the maintenance contractors would be capable of responding to all parts of the project within five hours. (M-10)

LSPGC indicated that it maintains master service agreements with transmission line contractors, vegetation management contractors, helicopter services, equipment suppliers, and material suppliers to supplement its staff and resources as may be necessary. (O-13)

LSPGC indicated that it would maintain communication and coordination with the ISO throughout the emergency repair process, maintain records of the event, and submit reports to the ISO in accordance with ISO agreements. (O-13)

LSPGC indicated that it would maintain critical spare parts and materials required to repair system facilities, including transmission structures, transmission conductor, and transmission insulators and hardware. In addition, LSPGC indicated that it maintains spare transmission structures, including emergency restoration structures, that can be utilized by LSPGC in the event of a failure. (O-15)

3.10.10 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC provided a list of transmission line and substation maintenance activities, as well as the frequency of those activities. The list included maintenance activities related to transmission towers and line, conductors, optical wires, switchyard, transformers, protection equipment, circuit breakers, battery systems, communication systems, buswork, as well as vegetation management. (CC-3)

VPC indicated that it would operate and maintain the project under the direction of one FTE. VPC indicated that its parent company would also use one FTE for supporting O&M activities. (CC-4)

VPC indicated that its O&M subcontractor would employ a project manager and four to six FTEs for maintenance activities.

VPC indicated that it has signed a proposal service agreement with its O&M contractor that describes the scope of services to be provided by the contractor.

VPC indicated that its O&M contractor would work with its maintenance partner for certain field maintenance of the proposed project. VPC indicated that its O&M contractor employs nearly 4,000 people in over 190 offices and plant sites in the U.S. and abroad. (M-1)

VPC indicated that its O&M contractor would be responsible for hiring qualified maintenance personnel for the project. (M-2)

VPC indicated that its O&M contractor's training manual is based on TPMs that have been successfully used by it for maintenance services across its client base nationally.

VPC indicated that its O&M contractor's training program utilizes classroom, learning management system content, self-study, and on-the-job training methods. (M-3)

VPC indicated that its O&M contractor plans to subcontract to support certain field maintenance activities.

VPC indicated that the maintenance program of its subcontractor is comprehensive and would comply with the ISO's maintenance standards. (M-4)

VPC indicated that the maintenance practices as listed in the TCA Appendix C 5.2.1 would be employed by its O&M contractor. (M-4)

VPC indicated that regardless of the project not being located in a High Fire Threat District, it would implement appropriate plans and procedures to minimize wildfire risk (Response to Qualification Question).

VPC indicated that it has already worked with the BLM to develop a preliminary wildfire plan to prevent, mitigate, and respond to fires during construction, operation, and maintenance of the project.

VPC indicated that IID's local experience would inform VPC's final wildfire mitigation plans and procedures. (M-5)

VPC indicated that its O&M contractor would have the responsibility to create and implement a compliant vegetation management plan that would comply with the applicable rules and decisions of the CPUC, NESC, ANSI, A300 Part 7: American operations integrated vegetation management and electric utility rights-of-way, and the International Society of Arboriculture best management practices. VPC indicated that the project would comply with vegetation management standards required by NERC and WECC. (M-5)

VPC indicated that in order to ensure compliance with its own standards, its O&M contractor performs assessments on its facilities on a three-year basis in which every program and procedure is assessed to ensure compliance.

VPC indicated that its O&M contractor's compliance experience with standards for inspection, maintenance, repair, and replacement of similar facilities include proven programs and scalable processes that enable successful O&M services on high-voltage transmission line.

VPC provided sample reports from its O&M contractor for transmission and distribution lines in California, which indicated that no anomalies were observed and that no vegetation was encroaching on the transmission line and concluded that the power lines appear to be in good condition with no loose or failing hardware. The reports include additional information on vegetation management. (M-6)

VPC indicated that its O&M contractor regularly reports on availability measures for its clients and that its current system is capable of capturing the necessary information to report on availability measures as described in TCA Appendix C Section 4.3. VPC indicated that in accordance with Section 4.3, the O&M contractor would generate and submit to VPC an annual report, which would be transmitted to the ISO within 90 days of the end of the calendar year. (M-7)

VPC indicated that adding the project to the ISO controlled grid would not require any changes or exceptions to the provisions of the TCA. (M-8)

VPC indicated that its O&M contractor plans to subcontract maintenance for the project with a qualified maintenance provider in the same locale as the project, as well as a project manager who would be located regionally.

VPC indicated that its O&M team would work with the VPC-designated representative on the ISO Transmission Maintenance Coordination Committee to ensure compliance with ISO transmission maintenance procedures and appropriate monitoring, tracking, and reporting of outages and project availability. (O-12)

VPC indicated that its O&M contractor has provided samples of emergency response plans for major fire operating procedure, transmission emergency plan, and system restoration plan.

VPC indicated that within two hours of an event, on-call local response field maintenance personnel would be on-site at assessed location, and within 24 hours, repair crews, equipment, and material would be on-site for live-line or typical corrective repairs. VPC indicated that repairs would be completed within 72 hours for small-scale events and 96 hours for large-scale events. (O-13)

VPC indicated that upon award of the project, VPC would continue its conversations with interconnecting utilities to explore mutual assistance agreements, storm restoration and disaster recovery arrangements, equipment storage agreements, shared inventory and spare parts agreements, and the like. (O-15)

Operating Practices

(Prior Projects and Experience Workbook; P-5, CC-3, CC-4, CC-5, O-1 through O-18)

3.10.11 Information Provided by CalGrid

CalGrid provided a list of its experience and the experience of its contractors with operating transmission lines. The list included a total of 14 transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years and are located in the U.S., with three in California. (Prior Projects and Experience Workbook)

CalGrid indicated that one employee would be assigned to oversee the O&M contractor. (CC-4)

Regarding the number of contractor personnel assigned for operations, CalGrid indicated that there would be 20 personnel – ten engineering support and ten operations management. (CC-5)

CalGrid provided an executed memorandum of understanding with its O&M contractor. CalGrid indicated that a subsidiary of its O&M contractor would fulfil the NERC functional role of Transmission Operator (TOP) for the project. CalGrid indicated that under these services, the operations contractor would be monitoring the operations of the line, including communicating with the ISO on the line's availability and coordinating with the maintenance team on any emergency or maintenance activities.

CalGrid indicated that its operations contractor is a NERC-registered TOP in WECC with 24 x 7 primary and backup control centers staffed with NERC-certified transmission system operators. (O-1)

CalGrid indicated that its operations contractor monitors the certification requirements for the Transmission Operator personnel, including progress and completion of required continuing education and emergency training requirements.

CalGrid described the qualifications, certifications and experience required for field personnel and the project manager. (O-2)

CalGrid indicated that it does not anticipate any exceptions to the provisions of the TCA regarding operations to integrate the project into the ISO controlled grid. (O-4)

CalGrid indicated that it would become the registered Transmission Owner (TO) and Transmission Planner (TP) for the project. CalGrid indicated that it expects its operations contractor to register as the Transmission Operator (TOP). (O-5)

CalGrid indicated that its operations contractor would develop the appropriate policies and procedures, maintain the proper documentation, and submit reports as required by NERC and/or the regional entity to be compliant with applicable TOP NERC reliability standards. (O-6)

CalGrid indicated that temporary waivers of TCA Section 5.1.6 would not be necessary. (O-7)

CalGrid indicated that its operations contractor has maintained and developed compliant facilities, programs, and procedures to support control center services for over 22 years.

CalGrid provided audit reports for the most recent audits, completed in 2022, by SERC and WECC. CalGrid indicated that both audits found no violations and no areas of concern. (O-8)

CalGrid indicated that its O&M contractor plans to enter a coordinator functional registration with the ISO. (O-9) CalGrid provided a list of relevant agreements, such as interconnection agreements and operating procedures with adjacent TOs. (O-10)

CalGrid indicated that its operations contractor has two remote data centers that are "hot-hot" to ensure no loss of data could occur.

CalGrid indicated that the EOP-008 loss of primary control center functionality was most recently audited in 2022, and there were no findings or areas of concerns by WECC or SERC.

CalGrid indicated that its operations contractor would install its field communications equipment, which generally would consist of router, switch, RTU, UPS and supplemental equipment to support physical access controls. (O-11)

CalGrid indicated that its operations contractor would be the primary point of contact for the ISO and neighboring Transmission Operators for voice communications, including ISO issued operating instructions. (O-12)

CalGrid indicated that the project would not be subject to any encumbrance. (O-14)

CalGrid indicated that neither it nor its O&M contractor or the subsidiary operations contractor, as a registered TO or TOP, have had any violations of NERC reliability standards in the past ten years. (O-16)

CalGrid indicated that neither it nor its O&M contractor or the subsidiary operations contractor have received any operations related tariff violations or FERC rules violations in the past ten years. (O-17)

CalGrid indicated that neither it nor its O&M contractor or the subsidiary operations contractor have incurred any violations of operations-related laws, statutes, rules, or regulations. (O-18)

3.10.12 <u>Information Provided by Horizon West</u>

Horizon West provided a list of its experience and the experience of its contractors with operating transmission lines. The list included a total of 57 transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years, and are located in the U.S., with three in California. (Prior Projects and Experience Workbook)

Horizon West indicated that it has prior operational experience in the ISO and provided examples of two projects in California where its affiliate was responsible for operations. (P-5)

Horizon West provided detailed information on the number of FTEs that would be used for various O&M job categories and their estimated utilization. Based on the information provided by Horizon West, the full-time FTE equivalent for performing all the O&M functions listed was approximately three FTEs. (CC-4)

Horizon West indicated that the project's operations would be undertaken by Horizon West field operations staff based in the vicinity of the project and by Horizon West's existing control center team, staffed by its system operating affiliate, Lone Star, located in Austin, Texas. Horizon West indicated that Lone Star is an existing ISO and WECC-certified Transmission Operator, which currently operates Horizon West's facilities with interconnection to SDG&E. Horizon West indicated that Lone Star has a track record of operating transmission assets under the ISO Tariff and interconnection protocols with incumbent investor-owned utilities.

Horizon West indicated that it and its affiliates' system operators are NERC-certified TOP operators.

Horizon West provided the minimum qualifications and experience, training, and certification requirements for its system operators and field personnel, including those involved in switching operations.

Horizon West indicated that its operations staff and Lone Star operations personnel supporting its projects are required to be familiar with the switching protocols contained in their emergency operation plan and required to take an annual switching refresher class to maintain qualification for conducting switching operations. (O-2)

Horizon West provided information on its training program, which included descriptions of training courses required by Horizon West for its operations personnel who are responsible for substation maintenance, system operations, P&C, and transmission lines and includes training for entry-level operations personnel. (O-3)

Horizon West indicated that it does not anticipate the addition of the project to the ISO controlled grid to require any changes or exceptions to the provisions of the TCA regarding operations. (O-4)

Horizon West indicated that Horizon West would perform the TO and TP function for the project under its registration and Lone Star, under its registration, would undertake the project's TOP role for Horizon West. (O-5)

Horizon West indicated that its compliance and responsibility organization would monitor its and Lone Star's execution of their NERC functional programs to ensure compliance with the reliability standards or requirements associated with the project. (O-6)

Horizon West indicated that it would follow NextEra's documented NERC reliability standards internal compliance program, which consists of compliance processes and procedures, effective independent oversight, effective training and education for roles and responsibilities, monitoring and auditing, internal controls, reporting possible violations or concerns, and corrective actions.

Horizon West indicated that it does not foresee any applicable reliability criteria for which TOs are responsible that would require temporary waivers under TCA Section 5.1.6. (O-7)

Horizon West indicated that Horizon West has had no violations relating to applicable NERC reliability standards. Horizon West provided results of NERC audits for the project operator Lone Star for the past ten years.

Horizon West provided the number of miles of transmission lines for which it and its affiliates are responsible for compliance. (O-8)

Horizon West indicated that in January 2020 Lone Star (the Horizon West NERC TOP) executed a Coordinated Functional Registration (CFR) agreement with the ISO.

Horizon West indicated that its operations team members have been instrumental in establishing several CFR agreements with the ISO.

Horizon West indicated that it and its operating system affiliate, Lone Star, would continue to work with the ISO as the CFR evolves, which includes defining roles and responsibilities related to complying with all applicable NERC TOP reliability standards requirements. (O-9)

Horizon West provided a table listing the applicable agreements that would define the project TOP's responsibilities and authority regarding other NERC functional entities. (O-10)

Horizon West indicated that the project would be integrated into its and Lone Star's existing control center infrastructure. Horizon West indicated that Lone Star would perform the system operations function for the project.

Horizon West described Lone Star's infrastructure for providing real-time operational information. (O-11)

Horizon West indicated that the project would not be subject to any encumbrance. (O-14)

Horizon West indicated that it has had no violations of NERC reliability standards in the past ten years. Horizon West provided a list that that identified and described NextEra's and the project sponsor's team violations in all NERC regions, including WECC. Horizon West indicated that for the project's system operator, Lone Star, and most NextEra entities in California, potential violations have been the subject of self-reports submitted to the applicable regional entity, WECC. (O-16)

Horizon West indicated that that there were no operations-related tariff violations or FERC rules violations the project sponsor or its team has incurred in the past ten years. (O-17)

Horizon West indicated that there were no violations of operations-related laws, statutes, rules, or regulations incurred by the project sponsor or its team in the past ten years. (O-18)

3.10.13 <u>Information Provided by Lotus</u>

Lotus provided a list of its experience and the experience of its contractors with operating transmission lines. The list included a total of two transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years, and are located in the U.S., with none in California. (Prior Projects and Experience Workbook)

Lotus indicated that it has faced operations-related risks and challenges similar to those foreseen for the project. (P-5)

Lotus indicated it is ensuring adequate communications and backup communications are installed early and checked frequently throughout the construction and commissioning phases of the project. (P-5)

Lotus provided an example of a recent transmission line project in California where it has been acting as a PTO. (P-5)

Lotus indicated that it would utilize its existing in-house asset management team to oversee its O&M contractor. Lotus indicated that its asset management team would consist of five FTE asset managers who would have additional accounting, finance, operations, and administrative support from Lotus' remaining 24 FTE's. (CC-4)

Regarding the number of contractor personnel assigned for operations, Lotus indicated that its operations contractor operates five shifts of four system operators per shift, including the shift supervisor. (CC-5)

Lotus indicated that it has signed a memorandum of understanding with its O&M contractor and its subsidiary operations contractor.

Lotus indicated that its operations contractor would be the ISO's single point of contact for project operations.

Lotus described the roles and responsibilities of each of the parties. (O-1)

Lotus indicated that its operations contractor currently has twenty system operator positions (including five shift leads), and it monitors the certification requirements for the Transmission Operator personnel, including progress and completion of required continuing education and emergency training requirements. (O-2)

Lotus indicated that its operations contractor maintains an initial and ongoing training program in accordance with PER-005 to ensure specific tasks and procedures, such as lock-out-tag-out, restoration, emergency response, and outage identification and coordination activities are covered.

Lotus also described the training requirements for field personnel. (O-3)

Lotus indicated that it does not anticipate any exceptions to the provisions of the TCA regarding operations to integrate the project into the ISO controlled grid. (O-4)

Lotus indicated that it would become the registered Transmission Owner for the project and its operations contractor would be registered as the TOP. (O-5)

Lotus indicated that its operations contractor would be responsible for compliance and that the O&M contractor's NERC team would provide technical leadership and program coordination in NERC program compliance and validation. (O-6)

Lotus indicated that it does not have any reliability criteria for which it would require a temporary waiver of TCA Section 5.1.6. (O-7)

Lotus indicated that all of the electric transmission facilities that its O&M contractor has operated have been in compliance with all applicable reliability standards.

Lotus provided an example of the CFR matrix that is under development with the ISO that lists NERC requirements and responsibilities of its operations contractor, customer, and the ISO. (O-9)

Lotus provided a list of relevant agreements, including interconnection agreements and TOP to TOP operating procedures. (O-10)

Lotus indicated that its operations contractor has two remote data centers that are "hot-hot" to ensure no loss of data could occur.

Lotus described the actions that would be taken by its operations contractor to provide the availability data required by TCA Appendix C Section 4.3. (O-11)

Lotus indicated that its operations contractor would be the primary point of contact for the ISO and neighboring transmission operators for voice communications, including ISO issued operating instructions. (O-12)

Lotus indicated that it is not anticipated that the project would be subject to an encumbrance. (O-14)

Lotus indicated that neither its O&M contractor nor its subsidiary operations contractor, as a registered TO or TOP, has had any violations of NERC reliability standards in the past ten years. (O-16)

Lotus indicated that it has no violations of NERC reliability standards in the past ten years. (O-16)

Lotus indicated that neither its O&M contractor nor its subsidiary operations contractor has received any operations related tariff violations or FERC rules violations in the past ten years.

Lotus indicated that it has no tariff related FERC violations or FERC rule violations to report. (O-17)

Lotus indicated that neither its O&M contractor nor its subsidiary operations contractor has incurred any violations of operations-related laws, statutes, rules, or regulations. Lotus indicated that it has not incurred any violations of operations-related laws, statutes, rules, or regulations. (O-18)

3.10.14 Information Provided by LSPGC

LSPGC provided a list of its experience and the experience of its contractors with operating transmission lines. The list included a total of five transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years, and are located in the U.S., with none in California. (Prior Projects and Experience Workbook)

LSPGC indicated that it has faced operations and maintenance-related risks and challenges similar to those foreseen for the project that includes operating and maintaining a line in a desert environment and provided a specific example of a project in Texas where it faced similar challenges. (P-5)

LSPGC provided the estimated number of FTEs for operations, maintenance, and administrative functions, as well as a breakdown of these FTEs by job function.

LSPGC estimated 3.8 FTEs for operations. (CC-4)

LSPGC indicated that it would be responsible for providing operations and compliance services for the project.

LSPGC indicated that it plans to operate the project from its control centers located in Austin, Texas. LSPGC indicated that its control centers would be integrated with the ISO in 2025 to operate the Orchard STATCOM and Fern Road GIS/STATCOM projects. LSPGC indicated that its control center facilities are NERC certified high impact rating control centers (per CIP-002-5) that are fully compliant with all NERC standards, including the physical and cyber security requirements necessary to operate the project.

LSPGC indicated that it trains and credentials local contractors to perform field operations at LSPGC facilities to supplement its internal resources as may be necessary from time to time (*e.g.*, for specialized maintenance and repair). LSPGC indicated that it does not use contractors for transmission system operator positions. (O-1)

LSPGC indicated that it requires that all transmission system operators hold: (1) Transmission Operator NERC certification and/or (2) Reliability Coordinator NERC certification. LSPGC indicated that the policies and procedures for operations personnel are guided by PER-003-02 and PER-005-02 and defined in LSPGC's operations training process manual.

LSPGC also provided the minimum experience and certification requirements for line and substation technicians and technicians performing switching activities. (O-2)

LSPGC indicated that it utilizes NERC's system operator certification and continuing education database to review and archive transmission system operator continuing education hours. LSPGC indicated that its transmission system operator training includes computer-based training, instructor-led courses, formal on-the-job training, simulations, drills, and exercises.

LSPGC indicated that to facilitate regular operating training, its SCADA/EMS system has an operator training simulator.

LSPGC indicated that field personnel are required to complete an annual training program, which includes topics such as emergency action plans, fall protection, hazard communications, CIP, code of conduct, switching, and environmental training.

LSPGC indicated that it assesses all contractors to ensure that their personnel have the appropriate training and expertise for the work before authorizing any work order. (O-3)

LSPGC indicated that it believes the addition of the project to the ISO controlled grid would require an amendment to TCA Appendix A to identify the project as under ISO control. (O-4)

LSPGC indicated that it would be registered with NERC as a TO, TOP, and TP for the Orchard and Fern Road STATCOM projects prior to operation of the project.

LSPGC indicated that it would add the project facilities to the WECC Bulk Electric System facilities list. (O-5)

LSPGC indicated that it would perform all NERC functions for the project. (O-6)

LSPGC indicated that the project would be integrated in its NERC internal compliance program, which is intended to provide a functional framework that outlines the guiding principles, governance structure, and internal compliance management activities implemented at LSPGC entities to support the secure and reliable operation of the bulk electric system and compliance with the NERC reliability standards.

LSPGC indicated that the chief compliance officer would be the NERC senior manager responsible for all NERC compliance. LSPGC indicated that its compliance management team would own oversight to ensure execution of day-to-day processes and controls while functional area leads would own and execute the day-to-day program and processes.

LSPGC indicated that it does not require any waivers under TCA Section 5.1.6. (O-7) LSPGC indicated that it is committed to maintaining compliance with the applicable reliability standards.

LSPGC indicated that in 2022, Texas RE in coordination with Reliability First Corporation conducted a compliance audit of certain LS Power utilities and that no findings of non-compliance with all the NERC reliability standards were found. (O-8)

LSPGC indicated that it would rely on the CFR that would be in place with the ISO for other LSPGC projects to divide responsibility for NERC reliability standards on this project. (O-9)

LSPGC indicated that the responsibilities and authority regarding the Transmission Owner and adjacent Transmission Operator(s) would be defined in an interconnection agreement with each respective adjacent Transmission Operator. (O-10)

LSPGC indicated that to the extent the project data isn't available via ISO ICCP, LSPGC would coordinate with APS and SDG&E to install data acquisition and communications equipment for the project at the North Gila and Imperial Valley substations to ensure adequate, reliable, and redundant data transmission and acquisition capabilities.

LSPGC indicated that its Austin, Texas control centers are NERC certified high impact control centers (per CIP-002-5) that currently operate extra high voltage substations and meet all of the physical and cyber security requirements necessary to operate the project. (O-11)

LSPGC indicated that it has the capability to comply with TCA Sections 6.1 and 6.3 through its existing operations. LSPGC indicated that its operating personnel and support teams at the control centers manage and coordinate all activities related to outages, including but not limited to operation, switching, scheduled maintenance coordination, forced outage management, and return to service.

LSPGC indicated that the project scope does not contain switchable equipment, so switching activities would be limited to the coordination of switching with APS and SDG&E.

LSPGC indicated that it would provide system monitoring and initial forced outage response on a 24/7 basis and a local California-based technician would be responsible for responding to any forced outages on the project. (O-12)

LSPGC indicated that it would be responsible for emergency response and repair on the project in coordination with the ISO. LSPGC provided its emergency operations plan, emergency response plan, and system restoration plan.

LSPGC indicated that the project would not be subject to any encumbrance on the ISO's operational control. (O-14)

LSPGC indicated that the Texas RE conducted a CIP audit of Cross Texas in 2019, which identified compliance violations of five standards. LSPGC indicated that in addition to mitigating each matter, it has significantly fortified enterprise compliance following the Texas RE audit of Cross Texas in April 2019. (O-16)

LSPGC indicated that neither it nor any of its affiliates has been found in violation of any operations-related tariff or FERC rules in the past ten years. (O-17)

LSPGC indicated that neither it nor any of its affiliates has been found in violation of any operations-related laws, statutes, rules, or regulations by any court or agency in the past ten years. (O-18)

3.10.15 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC provided a list of its experience and the experience of its contractors with operating transmission lines. The list included a total of 10 transmission line projects that operate at voltages above 200 kV and have been completed in the past ten years, and are located in the U.S., with seven in California. (Prior Projects and Experience Workbook)

For the VPC Dunes proposal, VPC provided a list of its experience and the experience of its contractors with operating substations. The list included a total of 15 substation projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, and are located in the U.S., with 11 in California. (Prior Projects and Experience Workbook)

VPC indicated that it has faced operations and maintenance risks similar to those foreseen for the project and provided several examples of projects that were related to noxious weed management, time frame for reclamation, and limited construction access. (P-5)

VPC indicated that its operations contractor, a subsidiary of its O&M contractor, operates five shifts of four system operators per shift, including the shift supervisor. (CC-5)

VPC indicated that it would operate and maintain the project under the direction of one full-time equivalent employee dedicated to managing operations and maintenance for the project, including project operations and compliance oversight, reporting to Grid United's vice president of project execution.

VPC indicated that it would also appoint an electrical regulatory compliance lead who would be responsible for ensuring the organization follows the compliance plan and satisfies all applicable NERC, WECC, and ISO compliance requirements, including the ones related to O&M.

VPC indicated that the compliance lead would also act as the authorized company representative and liaison with NERC, WECC, and the ISO. (O-1)

VPC indicated that its operations contractor staffs its transmission operations twenty-four hours a day, seven days a week with NERC reliability coordinator-certified system operators.

VPC indicated that its operations contractor currently has twenty system operator positions (including five shift leads), and it monitors the certification requirements for its TOP personnel, including progress and completion of required continuing education and emergency training requirements. (O-2)

VPC indicated that its O&M contractor would administer training for O&M personnel (including training and certification requirements for operators, linemen, etc.).

VPC indicated that the O&M contractor's training program encompasses all aspects of training, including management, operations, maintenance, environmental considerations, safety programs, and administration. (O-3)

VPC indicated that it would not require any changes or exceptions to the provisions of the TCA regarding operations. (O-4)

VPC indicated that Imperial Irrigation District's participation as a non-PTO and its associated Transmission Ownership Rights (TOR) would be governed by Section 17 of the ISO Tariff. VPC indicated that TORs are neither an entitlement nor an encumbrance under the ISO Tariff. VPC indicated that IID's rights to use transmission as a non-PTO would be effectuated through the issuance of Transmission Rights and Transmission Curtailment (TRTC) instructions, as defined in Section 17.1 of the ISO Tariff. (O-4)

VPC indicated that after award of the project, VPC would take steps with NERC and WECC to become the NERC-registered Transmission Owner and Transmission Planner and would bilaterally contract with its operations contractor as VPC's designated NERC-certified TOP and counterparty to an ISO CFR agreement. (O-5)

VPC indicated that the TOP Control Center Services Agreement contains terms and conditions obligating its operations contractor to meet compliance obligations and be responsible to NERC for any failures to meet those obligations. (O-6)

VPC indicated that it would also appoint an electrical regulatory compliance lead who would be responsible for ensuring the organization follows the compliance plan and satisfies all applicable NERC, WECC, and ISO compliance requirements, including the ones related to O&M. (O-1)

VPC indicated that it does not expect to require any temporary waivers under TCA Section 5.1.6.

VPC indicated that after the proposed project is awarded, it would commence the development and implementation of its NERC, WECC, and ISO compliance plan ahead of the proposed project's commercial operation date so as to meet the applicable reliability criteria. VPC described the key components of its compliance plan. (O-7)

VPC indicated that all of the electric transmission facilities that its O&M contractor has operated have been in compliance with all applicable reliability standards.

VPC indicated that since 2012 its O&M contractor has been through nearly 200 audits across its registrations with no audit-discovered violations. (O-8)

VPC indicated that it and its operations contractor are familiar with the ISO CFRs and the CFR matrices maintained on the NERC registry.

VPC provided an example of the CFR matrix that is under development with the ISO. (O-9)

VPC indicated that it would enter into the ISO TCA with the intent of becoming a PTO, which would give the ISO authority to perform the transmission service provider function relating to managing transmission resources within its balancing authority area. (O-10)

VPC indicated that its operations contractor would be providing TOP services that meet the reliability standard requirements of a NERC-certified TOP, including the obligations to have adequate and reliable data acquisition facilities for its TOP Areas and other TOP Areas. VPC indicated that the EOP-008 loss of primary control center functionality was most recently audited in 2022, and there were no findings or areas of concerns by WECC or SERC. (O-11)

VPC indicated that its operations contractor would be the primary point of contact for the ISO and neighboring TOPs for voice communications, including ISO-issued operating instructions and provided their TOP responsibilities.

VPC indicated that it does not anticipate the need for identification of encumbrances, as defined in the TCA. (O-14)

VPC provided a confidential report that listed a number of NERC violations by the Imperial Irrigation District, mostly the results of self-reports. (O-16)

VPC referenced a confidential report that included information about a Citizens Energy self-report process with FERC that was remedied and FERC staff took no further action. (O-17)

VPC indicated that no operations-related violations of laws, statutes, rules, or regulations, responsive to this question and occurring within the past ten years, have been identified. (O-18)

3.10.16 ISO Comparative Analysis

Comparative Analysis of Construction Practices

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the construction practices they propose for this project, including but not limited to their proposed design criteria and constructability review process. All of the project sponsors provided a detailed design criteria and constructability review processes that demonstrate that their respective projects would adhere to standardized construction practices. Based on these considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that there is no material difference among the proposals of CalGrid, Horizon West, Lotus, LSPGC, and VPC regarding this component of the factor.

Comparative Analysis of Maintenance Practices

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding adherence to applicable maintenance practices and the robustness of the maintenance practices they have proposed for this project, including but not limited to their proposed plans for compliance with NERC requirements for transmission owners and operators, the TCA, and the ISO's transmission maintenance standards.

The ISO has determined that all the project sponsors and their proposed teams have the basic capability to adhere to standardized maintenance practices. Some of the project sponsors and their teams have more well-established organizations and processes related to the maintenance of EHV transmission facilities than others do.

Both Horizon West and its team and LSPGC and its team have maintenance practices complying with the ISO's transmission maintenance standards under the TCA that have been approved by the ISO. The other project sponsors indicated that their maintenance practices include the elements of the ISO's maintenance standards.

The proposed emergency response and restoration times for all of the project sponsors are reasonable. Horizon West's proposal indicates it has more local resources available to respond to emergencies than the proposals of the other projects sponsors.

Regarding plans or provisions to be implemented by the project sponsor to replace major failed equipment, e.g., a group of towers (including dead end structures), Horizon West's proposal indicates greater access to spare parts through its affiliates than the other project sponsors do.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, Horizon West's proposal is slightly better than LSPGC's proposal (due to Horizon West's local resources available to respond to emergencies and greater access to spare parts), which is slightly better than the proposals of CalGrid, Lotus, and VPC (due to LSPGC's experience with complying with the ISO transmission maintenance standards), among which there is no material difference, regarding this component of the factor.

Comparative Analysis of Operating Practices

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the operating practices they propose for this project, including but not limited to their proposed emergency plans and other plans for compliance with NERC requirements for transmission owners and operators and the ISO's standards.

The ISO has determined that all the project sponsors and their proposed teams have the basic capability to adhere to standardized operating practices and standards and applicable tariffs. Some of the project sponsors and their teams have more experience and well-established organizations and processes related to operating EHV transmission facilities. The ISO considers it an advantage if the project sponsor has complied with the TCA as a PTO. For this analysis, the ISO considers transmission-related operating experience to be more important than generation-related operating experience.

Horizon West and its team and LSPGC and its team operate transmission facilities under the ISO's operational control that are required to comply with NERC standards, the TCA, and the ISO Tariff. None of the other project sponsors has operational transmission facilities operating under the ISO's operational control that are subject to the TCA and the ISO Tariff.

Regarding the approach the project sponsor would use to assure compliance with Applicable Reliability Standards, LSPGC does not plan to subcontract NERC functions, and Horizon West and VPC identified comprehensive corporate level compliance oversight functions that would include subcontractors. CalGrid and Lotus indicate that compliance management would be the responsibility of the subcontractor performing the TOP function.

Regarding compliance with the Applicable Reliability Standards for all transmission facilities that it owns, operates, or maintains, all project sponsors provided NERC audit reports indicating generally good compliance.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, there is no material difference between the proposals of Horizon West and LSPGC, and they are better than the proposals of CalGrid, Lotus, and VPC, among which there is no material difference.

Overall Comparative Analysis

The ISO considers the three components of this factor to be of roughly equal importance in the selection process for this project.

Regarding the first component of the factor (demonstrated capability to adhere to standardized construction practices), the ISO has determined that there is no material difference among the six proposals of the five project sponsors regarding this component of the factor.

Regarding the second component (demonstrated capability to adhere to standardized maintenance practices), the ISO has determined that Horizon West's proposal is slightly better than LSPGC's proposal, which is slightly better than the proposals of CalGrid, Lotus, and VPC, among which there is no material difference.

Regarding the third component of this factor (demonstrated capability to adhere to standardized operating practices), the ISO has determined that there is no material difference between the proposals of Horizon West and LSPGC, which are better than the proposals of CalGrid, Lotus, and VPC, among which there is no material difference.

Based on the combination of the foregoing comparisons for the three components of this factor, the ISO has determined that proposal of Horizon West is slightly better than the proposal of LSPGC, which is better than the proposals of CalGrid, Lotus, and VPC, among which there is no material difference regarding this factor overall.

3.11 Selection Factor 24.5.4(i): Ability to Assume Liability for Major Losses

(F-14, F-15, O-15)

The ninth selection factor is "demonstrated ability to assume liability for major losses resulting from failure of facilities of the Project Sponsor."

3.11.1 <u>Information Provided by CalGrid</u>

CalGrid indicated that prior to commencement of construction it would procure or cause its contractors to procure a builder's "all-risk" insurance policy in an amount that is not less than the full replacement cost of the project that will cover perils of flood, earthquake, windstorm, tornado, hail, lightning, freezing, strike, riot and civil commotion, vandalism, malicious mischief, and sabotage (non-terrorism events); subject to sub-limits and terms that are consistent with current industry practice. (F-14)

CalGrid indicated that upon completion of testing, commissioning, and achievement of substantial completion, the builder's risk insurance policy would expire and the property would be covered by an operational property policy. CalGrid indicated the operational property policy would provide coverage on a replacement cost basis in a broad form all-risk policy with limits that meet or exceed industry specific maximum foreseeable losses, with no co-insurance clause. CalGrid indicated the operational property policy would include coverage for mechanical and electrical breakdown, plus resulting or ensuing damage arising out of defects, the perils of flood, earthquake, windstorm, hail, tornado, lightning, sabotage (excluding sabotage by the named insured), strike, riot and civil commotion, vandalism, and malicious mischief, subject to terms that are consistent with current industry practice. (F-14)

During construction, CalGrid indicated it would require the construction contractor's corporate insurance program to include, but not be limited to, general liability, automobile liability, excess liability (including wildfire), worker's compensation, professional liability, and pollution liability coverage. CalGrid indicated that with respect to wildfire coverage, limits would be subject to commercial reasonableness, availability, and in line with prudent industry practice. (F-14)

During the operational life of the facilities, CalGrid indicated it would require the O&M contractor's corporate insurance program to include, but not be limited to, general liability (including wildfire), automobile liability, excess liability (including wildfire), and worker's compensation coverage. (F-14)

CalGrid indicated it would purchase general liability insurance (including wildfire) and excess liability insurance (including wildfire) over the operational phase of the facilities. CalGrid indicated the policy's limits would be in excess of the O&M contractor's contractually required limits and, with respect to wildfire coverage, limits would be subject to commercial reasonableness, availability, and in line with prudent industry practice. (F-14)

CalGrid indicated its approach to risk management would follow prudent utility practice. CalGrid indicated that should CalGrid's exposure extend beyond its anticipated insurance coverage, it expects that any additional uninsured exposure would be eligible for recovery at FERC. (Attachment G1-1 Wildfire Plans and Procedures)

CalGrid indicated major capital replacements and rebuilds over the life of the project would be financed through retained earnings, owner cash reserves, revolving lines of credit, insurance proceeds, and additional parent support to the extent required. (F-15)

CalGrid indicated it would maintain cash operating reserves and a line of credit to cover unexpected capital replacements, as well as insurance coverage for catastrophic events. (F-15)

CalGrid indicated that an emergency response and spare equipment program is being evaluated and discussions are underway on how to maximize the ability to respond to such events, including the use of its O&M contractor and other providers to maximize ability to respond, minimize costs, and provide these services in accordance with good utility practice. (O-15)

CalGrid indicated that for hardware and insulators, its construction contractor would procure and hold a small percentage (2-3%) of construction spares for loss and breakage during construction and would transfer any unused spares to CalGrid and the O&M contractor to have at project startup.

CalGrid indicated that during commercial operations, the O&M contractor would carry an inventory stock of 1-3% for hardware and insulators as O&M spares for use when damage or issues are noted during inspections in accordance with prudent utility practice. (O-15)

3.11.2 Information Provided by Horizon West

Horizon West indicated that NextEra and its affiliated, subsidiary, and associated companies and corporations, which includes Horizon West, maintain and will maintain a property all-risk insurance program that would cover the project facilities from all risks of direct physical loss or damage, including, but not limited to, mechanical and electrical breakdown, wildfire, flood, earthquake, windstorm, and terrorism. (F-14)

Horizon West indicated it maintains and would maintain a commercial general liability insurance program with limits commensurate with industry standards that would protect against liability claims for bodily injury and property damage. (F-14)

Horizon West indicated the insured values during construction and over the operational life of the project facilities would not be less than the full replacement cost of the facility and include the entire extent of the failure of project facilities during the operation of the project. (F-14)

Horizon West indicated that during construction and operations it would have in place property insurance, general liability insurance, workers compensation insurance, auto liability insurance, pollution liability insurance, professional liability insurance, excess umbrella liability insurance and wildfire liability insurance. Horizon West indicated that it currently maintains a corporate NextEra general umbrella liability policy, including a California wildfire sublimit in the hundreds of millions of dollars. (F-14)

Horizon West indicated it would rely on its internal financial resources, including operating revenues from its projects as well as its NEECH debt facility, to fund unexpected repairs during the project's expected useful life. (F-15)

Horizon West indicated that it would maintain a spare stock of critical transmission line components, hardware, wire, and structures to ensure expedient recovery in the event of an emergency.

Horizon West indicated that in addition to spares on-site, it would have access to its affiliate-wide spares sharing program, specifically Florida Power & Light Company spares and strategic support of equipment suppliers. Horizon West indicated that the project would be built to NextEra equipment design standards to the extent possible so that the project could be incorporated into the larger NextEra spare parts management program. (O-15)

3.11.3 Information Provided by Lotus

Lotus indicated that it would require its construction contractor to carry its own insurance during the construction phase of the project. (F-14)

Lotus indicated it plans to have an insurance package that would include what is typical of industry standards and required for debt financing. Lotus indicated the operating period insurance package would include but not be limited to two main components pertaining to wildfire: (i) all risk property insurance and (ii) general excess liability insurance. Lotus indicated the risk property component would cover the replacement cost of the project anticipated not to be subject to fire related sublimits and the general excess liability component would be anticipated to provide additional coverage of property damage caused by a wildfire. (P-5)

Lotus indicated it would be able to finance unexpected repairs through a number of different financing sources, including but not limited to a revolving credit facility, equity contributions, long-term service agreements, and project or fund cash balances. (F-15)

Lotus indicated that for hardware and insulators, its construction contractor would procure and its O&M contractor would carry a small percentage of construction spares for loss and breakage during construction. Lotus indicated that during commercial operations, its O&M contractor would plan to carry an inventory stock of one to three percent for hardware and insulators as O&M spares for use when damage or issues are noted during inspections. (O-15)

3.11.4 Information Provided by LSPGC

LSPGC indicated that it would maintain insurance coverages with companies rated “A-” or better throughout the construction period and operational life of the project. LSPGC indicated that insurance coverages applicable to the project would include commercial general liability, auto liability, workers compensation, umbrella and excess liability, aircraft liability, and sudden and accidental pollution liability. (F-14)

LSPGC indicated that during construction it would be protected by builder’s all-risk insurance coverage. LSPGC indicated that once operational the project would be included in LS Power’s property all-risk insurance program with a sub-limit applicable to transmission lines, which is anticipated to cover the loss from a single event. (F-14)

LSPGC indicated that its insurance coverage for damages due to wildfires currently affords approximately $100 million in total liability limits. (Response to qualification questions)

LSPGC indicated it would maintain cash operating reserves and a line of credit to cover unexpected capital replacements as well as insurance coverage for catastrophic events. (F-15)

LSPGC indicated that it would maintain critical spare parts and materials required to repair system facilities, including transmission structures, transmission conductor, and transmission insulators and hardware. In addition, LSPGC indicated that it maintains spare transmission structures, including emergency restoration structures that can be utilized in the event of a failure. (O-15)

3.11.5 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC indicated it would require its contractors and subcontractors to have minimum coverages and limits based on type of work and relative level of risks. (F-14)

VPC indicated that during construction, VPC would maintain project-specific insurances for the project in respect of builder's risks insurance, contingent cargo, if applicable, third-party liability, workers compensation, if applicable, and pollution legal liability.

VPC indicated that during the operational phase it would maintain project-specific insurances in such amounts and covering such risks as are usually carried by companies engaged in the same or similar business and which is commercially available and reasonable including all risks of physical loss or damage, business interruption (if applicable and reasonable), third party liability, workers compensation, and any insurance required by law.

VPC indicated it did not include specific coverage for wildfire damage in its assumed insurance costs. VPC indicated that this is prudent because the project is not located in a High Fire Threat District and VPC does not wish to burden ISO ratepayers with unnecessary costs. (Response to qualification question)

VPC indicated future financing for any unexpected repairs would be expected to be financed in a similar manner to the project, based on an expectation of the ability to recover prudently incurred costs for such repairs.

VPC indicated financing for unexpected repairs would be expected to include equity from VPC, funded by an equity commitment from Grid United, and debt financing similar to that proposed for the project, dependent on the then-current debt market conditions. (F-15)

VPC indicated that upon award of the project, VPC would continue its conversations with interconnecting utilities to explore mutual assistance agreements, storm restoration and disaster recovery arrangements, equipment storage agreements, shared inventory and spare parts agreements, and the like. (O-15)

3.11.6 ISO Comparative Analysis

For purposes of the comparative analysis for this factor, the ISO has considered the representations by the project sponsors regarding their resources and plans for assuming responsibility for losses resulting from failure of project facilities, including but not limited to their financial resources, proposed insurance, and other plans for mitigation of equipment failures.

Failures of project facilities would likely represent only a portion of the investment in the project, e.g., a number of towers, a limited number of spans of wire, damaged insulators, etc. However in the event where a project facility is found as the cause of a wildfire, the potential for losses, in part due to third party impacts from such a wildfire, could be extensive, even multiple times more than the replacement cost of the transmission facility.

The ISO will consider the ability of a project sponsor to withstand major losses such as those due to wildfires as part of the comparative analysis. The ISO understands that this project is not located in a High Fire Threat District; however, the threat of a wildfire cannot be ruled out, and therefore the ISO considers whether project sponsors are financially prepared for such an event to be an advantage.

Financial Resources

As discussed above and in Section 3.7 of this report, the financial resources of the project sponsors vary and the ISO has concluded that the proposals of CalGrid and Horizon West are the strongest in this regard, followed by LSPGC's proposal and then the proposals from Lotus and VPC, for its two proposals.

Insurance

CalGrid, Horizon West, Lotus, and LSPGC indicated that during construction and the life of the project there would be an all risk insurance policy in place for the replacement cost of the project, including excess liability insurance that covers wildfires. Horizon West indicated that it would have in place hundreds of millions of dollars in additional wildfire liability insurance for California fire-related liability coverage, which is more than any of the other project sponsors. LSPGC indicated that its insurance coverage for damages due to wildfires currently affords approximately $100 million in total liability limits, which is more than CalGrid, Lotus, or VPC. VPC indicated that during construction it would be protected by its contractor's insurance coverage and once operational it would maintain an all-risk insurance policy; however, VPC did not provide coverage amounts. VPC indicated that it did not include specific coverage for wildfire damage in its assumed insurance costs.

Based on the foregoing, the ISO has determined the proposal of Horizon West is better than the proposal of LSPGC, which is better than the proposals of Lotus and CalGrid, between which there is no material difference, which are better than the two proposals of VPC, regarding insurance coverage for potential major losses.

Mitigation of Equipment Failures

The ISO has determined that Horizon West's proposal is slightly better than the proposals of CalGrid, Lotus, LSPGC, and VPC regarding the ability to mitigate major equipment failures because it would have greater access to spare parts through its affiliates. The ISO has determined that there is no material difference among the proposals of CalGrid, Lotus, LSPGC, and VPC regarding this matter.

Overall Analysis

The ISO considers the three components of this factor to be of roughly equal importance in the selection process for this project. Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, the proposal of Horizon West is better than the proposals of CalGrid and LSPGC, between which there are offsetting strengths and weaknesses resulting in a conclusion that there is no material difference, which are better than the proposal of Lotus, which is slightly better than two proposals of VPC, regarding this factor overall.

3.12 Selection Factor 24.5.4(j): Cost Containment Capability, Binding Cost Cap and Siting Authority Cost Cap Authority

The tenth selection factor is "demonstrated cost containment capability of the Project Sponsor and its team, specifically, binding cost control measures the Project Sponsor agrees to accept, including any binding agreement by the Project Sponsor and its team to accept a cost cap that would preclude costs for the transmission solution above the cap from being recovered through the ISO's Transmission Access Charge, and, if none of the competing Project Sponsors proposes a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the Project Sponsor, and its history of imposing such measures." As discussed in Section 2.1 of this report, the ISO identified this selection factor as a key selection factor for this project because under ISO Tariff Section 24.5.1, binding cost containment commitments are a key selection factor in every ISO competitive solicitation.

For the purpose of performing the comparative analysis for this factor, the ISO initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) demonstrated cost containment capability of the project sponsor and its team, including any binding agreement by the project sponsor and its team to accept a cost cap that would preclude project costs above the cap from being recovered through the ISO's transmission access charge, and (2) if none of the competing project sponsors propose a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the project sponsor and its history of imposing such measures.

All five project sponsors provided binding capital cost containment proposals for their six proposals. The proposals had various provisions regarding cost escalation. The ISO retained a well-respected expert consulting firm to assist, *inter alia,* in evaluating the project sponsors' cost containment proposals and conducting cost of service and revenue requirement studies. The studies and analyses conducted by the consulting firm were extensive, including numerous sensitivity analyses. In addition to evaluating the proposals regarding their proposed binding cost containment measures, the ISO evaluated each project sponsor's proposal considering the following additional factors relating to cost containment:

- Cost containment performance for past projects
- Project management capabilities
- Project risks and mitigation of risks

Cost Containment Capability Including Binding Cost Cap

(Prior Projects and Experience Workbook, Cost and Cost Containment Workbook; P-1, P-2, P-4, CC-1 through CC-15, S-1)

3.12.1 <u>Information Provided by CalGrid</u>

Cost Containment

CalGrid proposed the following cost containment measures:

- a cap on its return on equity (ROE);
- an annual revenue requirement cap for a limited period of time;
- a financial incentive penalty for failure to energize the project by an in-service date of June 1, 2032

(CC-1, Cost and Cost Containment Workbook)

CalGrid proposed specified limited exclusions to its cost containment measures and rate treatment for any incurred costs associated with such exclusions. (CC-1, CC-7)

Cost Containment Performance for Past Projects
CalGrid provided a list of project experience for its transmission line projects that included actual cost versus budget performance. CalGrid provided budget and actual cost information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project.

Regarding transmission line projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the list included 12 projects, 11 of which were completed and one of which is ongoing. CalGrid indicated that all of the 11 projects that were completed were completed at or below budget. CalGrid indicated that ten projects with original budgets less than $150 million were completed 5% below budget on average. CalGrid indicated that two projects with original budgets greater than $700 million, but less than $800 million, were completed 6% below budget on average. (Prior Projects and Experience Workbook)

Project Management Capabilities
CalGrid indicated that its proposed project management steps include project kickoff and scoping, schedule development, risk identification and mitigation plans, and cost estimates, and CalGrid provided detailed information for these steps. (P-1)

Regarding cost estimates, CalGrid indicated that it has performed internal analyses and benchmarking to ensure the project cost estimates were accurate, complete, and competitive against relevant benchmarks. (P-1)

CalGrid described its approach to project management execution, which includes project controls, project communication, quality management, risk management, procurement coordination, and safety management. (P-1)

CalGrid also provided information on its project management leadership team that would bring decades of experience in management of projects. (P-2)

Project Risks and Mitigation of Risks
CalGrid provided a risk log that included 67 risk items grouped into several risk categories (permitting, procurement, construction, rights-of-way, operations etc.), the risk

consequence (cost, schedule) and the likelihood of the risk (low, medium, high). The risk log also includes the owner of each risk (CalGrid, ISO), as well as the mitigation measure for each risk item. (P-4)

CalGrid indicated that while initial conversations with the Fort Yuma Quechan Tribe were encouraging and CalGrid is optimistic about a route that uses tribal land, the route is not without risk. CalGrid indicated that the risk of crossing the reservation includes securing rights-of-way from the Fort Yuma Quechan Tribe and the BIA in a form that is satisfactory to all parties. CalGrid indicated that a resolution from the Fort Yuma Quechan Tribe approving the portion of the project that traverses reservation land would be needed for the BIA to issue a grant of easement for rights-of-way. (E-2)

3.12.2 Information Provided by Horizon West

Cost Containment
Horizon West proposed an annual revenue requirement cap for the first full 15 years of operation (Horizon West ARR Cap Proposal). Under this proposal, Horizon West indicated that the annual revenue requirement cap in year 1 would be $43,769,000, and in year 15 would be $34,835,000. (CC-1, Cost and Cost Containment Workbook)

Horizon West also proposed a soft capital cost cap that would limit its ROE to 5% on project costs in excess of $256 million over the life of the project. Horizon West noted that this soft capital cost cap does not limit its ability to recover other components of its annual revenue requirement (ARR), nor does it limit the rate used to calculate a return on construction work in progress (CWIP) or allowance for funds used during construction (AFUDC) during the construction period. (CC-1)

Horizon West proposed exclusions to its cost containment provisions for both the ARR and soft capital cost cap limited to the incremental costs incurred because of:

1. A change in the ISO project requirements or the ISO Functional Specifications;
2. A change in law, tax rates, or property tax assessment methodology after submission of its proposal;
3. Uncontrollable Force, as defined in the ISO Tariff;
4. Changes by a transmission owner other than Horizon West, including, but not limited to, changes in project scope of work or location, delays to interconnection, costs associated with mitigation for sub-synchronous resonance, impact study, path rating study, facilities study, or other studies requested by any interconnecting PTO, entity providing transmission interconnection, affected system operator, the ISO, or any other entity;
5. Costs associated with capitalized expenditures incurred after the project commercial operating date;
6. The undergrounding of any portion of the transmission line;
7. Losses or liabilities in excess of insurance policy coverages; and
8. CWIP or AFUDC.

(CC-7)

Horizon West indicated that additional costs associated with mitigation measures beyond those assumed in its proposal were excluded. (CC-7, Attachment 5 CC-7a)

Horizon West indicated that it would not seek relief from its proposed cost caps and cost containment measures for any siting or permitting authority directive to relocate the project. (CC-9) Furthermore, Horizon West affirmed that costs associated with directives to change structures, equipment, or transmission lines, directives to relocate, or delays in receipt of siting or permit authorizations are covered under Horizon West's cost containment. (Request for Clarification #2)

Horizon West indicated that due to its extensive due diligence, it would assume all the risk of re-routes of the project, protecting the ISO's ratepayers from the risk that the proposed route gets longer. (L-1)

Horizon West indicated that it would not seek relief from its proposed cost caps and cost containment measures for any siting or permitting authority directive to change the proposed structures, equipment, or transmission lines associated with the project. (CC-10)

Horizon West indicated that its proposed cost caps and cost containment measures exclude costs incurred as a result of a siting or permitting authority directive to require incremental mitigation for the project beyond that assumed in its proposal, including alternative best management practices and increased compensatory mitigation. (CC-11)

Horizon West indicated that its proposed cost caps and cost containment measures exclude costs related to a directive by any entity that would require it to underground the line. (CC-12)

Horizon West indicated that if there were to be a delay in the receipt of any of Horizon West's siting or permit authorizations, Horizon West would not seek relief from its proposed cost cap and other cost containment measures. (CC-13)

Horizon West indicated that costs caused by other transmission owners are excluded from Horizon West's cost containment proposal. (CC-14)

Horizon West's proposal included a financial incentive penalty for failure to deliver the project by an in-service date of December 31, 2031, with a reduction in its ARR cap of 0.2% for every full calendar month that the project's energization is delayed beyond December 31, 2031, up to a maximum of 1.2%. (CC-1)

Cost Containment Performance for Past Projects
Horizon West provided a list of project experience for its transmission line projects that included actual cost versus budget performance. Horizon West provided budget and actual cost information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project.

Regarding transmission line projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the list included 54 projects. Of these 54 transmission line projects, 34 were completed at or below budget and 20 were completed above budget.

The projects that were completed below budget were completed below budget by an average of 4% and the average budget of these projects was $400 million. Similarly, the projects that were completed above budget were completed above budget by an average of 4% and the average budget of these projects was $320 million. (Prior Projects and Experience Workbook)

Project Management Capabilities
Horizon West provided information regarding its five phases of project management, which includes project launch and initiation, project planning, project execution, project monitoring and controlling, and project closeout. (P-1)

Regarding project execution, Horizon West indicated that the project management team, led on a day-to-day basis by the project manager, would then begin working on the tasks and milestone deliverables identified within the project execution plan using technology platforms such as Microsoft SharePoint and Primavera Unifier to facilitate the exchange of project information, engineering plans, and drawings. (P-1)

Regarding monitoring and control, Horizon West indicated that the project schedule, budget, and risk logs for the project would be updated based on current information. (P-1)

Project Risks and Mitigation of Risks
Horizon West provided a risk and issue log that identified 24 high-level set of risks, category of risk, whether it affects cost or schedule, the probability of occurrence, the impact of the occurrence, whether it is a risk during development or construction, and both completed and potential mitigation. (P-4)

Horizon West indicated that the major risks to the project include routing risk, delay in the CPCN process, and construction cost risk and in each case identified mitigation measures. (P-4)

3.12.3 Information Provided by Lotus

Cost Containment
Lotus proposed the following cost containment measures:

- a nominal capital cost cap;
- a return on equity cap; and
- an additional cost containment incentive in the event of an increase in project cost, in which Lotus would absorb a set amount of additional cost increase before the exclusion would be triggered.

(CC-1, Cost and Cost Containment Workbook)

Lotus indicated that the nominal cost cap provided in its proposal was for information only and did not include an inflation cap and that when Lotus files its transmission revenue requirement rate case with FERC prior to the in-service date of the project, the filling submitted would include actual incurred inflation, and the project would seek to demonstrate the prudence of the amount. (Cost and Cost Containment Workbook and validation response)

Lotus proposed specified exclusions to its cost containment provisions and agreed to certain cost containment measures if certain exceptions are triggered. (CC-8-CC-14)

Cost Containment Performance for Past Projects
Lotus provided a list of project experience for its transmission line projects that included actual cost versus budget performance. Lotus provided budget and actual cost information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project. (Prior Projects and Experience Workbook)

Regarding transmission projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the list included one project. This project is ongoing and information regarding planned or actual (current) budget was not provided because this information was deemed by Lotus to be confidential. (Prior Projects and Experience Workbook)

Project Management Capabilities
Lotus indicated that through respective contractors, it would develop plans that include preconstruction, coordination with APS and SDG&E, FERC filings, public outreach plan, and APS and SDG&E interconnection applications. (P-1)

Lotus also indicated that during the preconstruction phase, it would develop plans for procurement, health and safety, project execution, environmental management, electrical studies, interconnection studies, etc. (P-1)

Project Risks and Mitigation of Risks
Lotus provided a list of major risks and obstacles that included lack of detailed system data for design, siting and land acquisition, environmental permitting, cost containment, and its ability to develop multiple projects simultaneously. Lotus also provided mitigation measures for these risks and obstacles. (P-4)

Regarding siting and land acquisition, Lotus identified failing to garner the willingness of landowners to participate in negotiations as the highest risk and indicated its experience in anticipating and addressing landowner questions and concerns. Lotus also indicated that its affiliates have the tools and resources to investigate land ownership changes and locate contact information to establish contact with the new landowner. (P-4)

Lotus indicated that it has thoroughly evaluated the risk of securing land rights on the Fort Yuma Quechan Tribe reservation and that if an agreement for an easement over reservation land could not be reached, Lotus would notify siting and permitting agencies of such, declare the route over the reservation land as infeasible, and proceed with its alternative route. Lotus indicated that the alternative route is approximately eight miles longer than its preferred route. (L-1)

Regarding environmental permitting and mitigation, Lotus indicated that its experience with this process for a similar transmission project mitigates the risk associated with this process, which could take several years. (P-4)

3.12.4 Information Provided by LSPGC

Cost Containment

LSPGC proposed the following cost containment measures:

- an annual revenue requirement cap for a limited period of time; and
- a financial incentive penalty for failure to complete the project by an in-service date of June 1, 2032.

(CC-1; Cost and Cost Containment Workbook)

LSPGC also proposed specified exclusions to its proposed cost caps and committed to certain cost containment measures if certain exclusions are triggered. (CC-1, CC-9-CC-15)

Cost Containment Performance for Past Projects
LSPGC provided a list of project experience for transmission line projects from LS Power that included actual cost versus budget performance. LSPGC provided budget and actual cost information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project.

Regarding transmission line projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the list included eight projects. All of the eight transmission line projects were completed at or below budget. Three projects with original budgets less than $60 million were completed 6% below budget on average. Four projects with original budgets greater than $100 million, but less than $400 million were completed either on budget or 6% below budget on average. One project above $400 million but below $500 million was completed on budget. (Prior Projects and Experience Workbook)

Project Management Capabilities
LSPGC provided information for its project management approach, which included risk management, schedule management, cost management, project communication, quality management, issues management, and safety management. (P-1)

Regarding cost management, LSPGC indicated its approach is active management of the budget and that early identification of variance trends would enable the project team to resolve budget issues before they become substantial. (P-1)

Project Risks and Mitigation of Risks
LSPGC provided a project risk register that included 73 risk items in six risk categories – cost containment, project management and schedule, environmental permitting and public process, land acquisition, engineering and design, and construction. Each risk item included a rating for risk likelihood, risk consequence, risk level to ISO ratepayers and risk level to LSPGC. Each risk item also included a mitigation measure. (P-4)

LSPGC also identified major risks to the project, such as interest rate increases, equipment and materials cost increases, and regulatory mandated deviations, and provided the mitigation measures that it has adopted. (P-4)

3.12.5 Information Provided by VPC for VPC and VPC Dunes Proposals

Cost Containment
VPC, for both of its proposals, proposed the following cost containment measures:

- a declining or levelized annual revenue requirement cap for a limited time, with a different cap for the VPC proposal and VPC Dunes proposal;

(CC-1, Cost and Cost Containment Workbook)

VPC proposed specified exclusions to its cost containment measures for both proposals. (CC-1, CC-9-CC-15)

Cost Containment Performance for Past Projects
For both proposals, VPC provided a list of project experience for its transmission line projects that included actual cost versus budget performance. VPC provided budget and actual cost information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project.

Regarding transmission line projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the list included four applicable projects. Of these four transmission line projects, three were completed below budget, one was completed above budget. The three projects that were completed below budget were small projects (less than $3 million) that were completed below budget due to scope reduction. One project with a budget of approximately $30 million was above budget by 2.5% due to an increase in project scope. (Prior Projects and Experience Workbook)

Project Management Capabilities
For both proposals, VPC indicated that its project management approach covers around twenty areas, including resource management, risk management, project administration and document control, safety monitoring and reporting, materials management, construction planning, construction management, permitting, environmental compliance, community outreach, and project close out. (P-1)

Project Risks and Mitigation of Risks
For both proposals, VPC indicated that the major risks to the project include permitting delays, cost of private rights-of-way, material and equipment pricing, subsurface conditions, and labor availability. For both proposals, VPC also included the mitigation measures for these risks. In addition, VPC included as risk matrix that identified several financial risks to VPC and the ISO, their probability, impact, and mitigation measures. For both proposals, VPC indicated that this matrix would continue to be updated as the project continues development. (P-4)

Authority to Impose Binding Cost Caps

(CC-16)

3.12.6 Information Provided by CalGrid

CalGrid indicated that this is inapplicable because CalGrid is proposing binding cost control measures. (CC-16)

3.12.7 Information Provided by Horizon West

Horizon West indicated that its transmission rates are regulated by FERC, and therefore the binding cost containment measures that Horizon West proposes for the project will primarily be enforced by FERC, through the Approved Project Sponsor Agreement and Horizon West's FERC-approved transmission rates. (CC-16)

3.12.8 Information Provided by Lotus

Lotus indicated that FERC has the authority to impose cost control measures in the context of rate setting and that while the CPUC has a statutory mandate to establish maximum reasonable cost, the CPUC's authority over costs in this context is preempted by federal law. (CC-16)

3.12.9 Information Provided by LSPGC

LSPGC indicated that this is inapplicable because LSPGC is proposing binding cost control measures. (CC-16)

3.12.10 Information Provided by VPC for VPC and VPC Dunes Proposals

VPC indicated that this is inapplicable because VPC is proposing binding cost containment measures. (CC-16)

3.12.11 ISO Comparative Analysis

Comparative Analysis of Cost Containment Capability Including Cost Cap Agreement

For purposes of the comparative analysis for this component of the factor, the ISO's analysis considered the expected effectiveness of the project sponsor's overall cost containment capabilities, including, but not limited to, cost containment performance on prior projects; project management and scheduling organizations and capabilities; experience of key individuals; the project risk and mitigation that each project sponsor identified; factors affecting cost; and proposed cost containment plans and proposed binding cost caps.

In addition, for purposes of this comparative analysis, the ISO considers the potential benefits from an in-service date for this project in advance of the latest in-service date specified in the ISO Functional Specifications to be uncertain based on the information currently available to the ISO. In particular, the ISO anticipates that the need that the project is intended to address will not exist prior to June 1, 2032. With this in mind, the ISO has chosen to evaluate the project based on the latest in-service date specified in the ISO Functional Specifications. If the project can be placed into service earlier and the interconnection facilities necessary to accommodate the project are completed sooner than expected, the ISO would anticipate seeking to negotiate an earlier in-service date with the approved project sponsor when the ISO has better information regarding the potential benefits (and risks) of achieving an earlier in-service date.

Cost Estimates

The project sponsors provided a range of cost estimates for capital costs and operations and maintenance costs. The differences in cost estimates are reflected in the proposed annual revenue requirements and binding cost caps proposed by each project sponsor. The ISO discusses below potential site and route-related risks associated with particular projects. The ISO has not identified any significant physical site-related risks, physical project features, or special construction techniques that would inherently or materially increase the costs of a particular project sponsor's project or pose a distinct cost or cost escalation risk not accounted for by a project sponsor.

Binding Cost Containment Measures and Cost Containment Exclusions

All five project sponsors committed to some form of binding cost containment measures subject to certain specified exclusions and conditions for adjustment. However, the robustness of the cost containment measures varies greatly. Consistent with the practice the ISO implemented in connection with the competitive solicitation for past projects and to respect confidentiality concerns, the ISO only specifies in this section the specific, detailed estimated cost and cost containment measures and conditions of the approved project sponsor. The estimated cost and cost containment measures and conditions proposed by the other project sponsors are described only in very general terms.

Horizon West proposed a limited or soft capital cost cap and a 15-year annual revenue requirement cap. The soft capital cost cap provides for a reduction in Horizon West's ROE from 9.8% to 5.0% for any incremental capital expenditures greater than the project capital cost estimate of $256 million over the life of the project. In addition, Horizon West provided an annual revenue requirement cap for the first 15 years of the project. Incremental costs are subject to the soft capital cost cap up to the value of the annual revenue requirement cap for any given year in the first 15 years. Costs above Horizon West's annual revenue requirement cap would not be recovered.

Horizon West's annual revenue requirement caps provided for the first 15 years of operations range from $43.8 million in year 1 to $34.8 million in year 15. These caps are set higher than the projected actual annual revenue requirements, which limits the effectiveness of the proposed on-time incentive. However, the proposed caps are similar in value to CalGrid's, LSPGC's, and VPC's proposed caps for this period.

CalGrid, LSPGC, and VPC (for both of its proposals) provided robust cost containment provisions through their proposed annual revenue requirement caps. These caps are proposed for a much longer period than the annual revenue requirement caps proposed by Horizon West. However, the CalGrid, LSPGC, and VPC proposals have significantly higher evaluated estimated present value annual revenue requirements, primarily due to those proposals having higher proposed capital costs and associated revenue requirement caps. Lotus provided a capital cost cap and noted that the cap was informative only. Lotus also provided a financial commitment to absorb costs up to a certain amount before seeking recovery regardless of the cause of the increase.

There is a difference between the VPC proposals based on the estimated capital costs used as a basis for the annual revenue requirement cap for each respective proposal. The ISO believes that without IID participation, there is no identified need for the Dunes substation, and without the Dunes substation the benefits to IID participating in the transmission line only project are unclear. For this reason, the ISO chose to focus on VPC's Dunes proposal inclusive of IID and the VPC transmission line only proposal excluding IID participation. Because the VPC Dunes proposal includes a cost sharing agreement with IID, the VPC Dunes proposal inclusive of IID participation provides a lower present value of the estimated revenue requirements in the analysis than the present value of the estimated revenue requirements of the VPC transmission line only proposal, excluding IID participation.

Both CalGrid and Lotus also provided ROE caps for the life of their respective projects, and CalGrid provided specific transmission structure modification caps.

All proposals included numerous siting-related costs that would be excluded from their binding cost caps. Many of these siting-related cost cap exclusion items are common across all of the project sponsors' proposals. The proposal of Horizon West included the fewest cost cap exclusions, specifically noting that route and structure changes and a limited number of changes to its environmental mitigation assumptions would be covered by its cap provisions and not treated as excluded costs.

The longer-term annual revenue requirement caps offered by CalGrid, LSPGC, and VPC are more robust than the soft capital cost cap and the 15-year annual revenue requirement cap offered by Horizon West. However, despite Horizon West's more limited cost containment as compared to CalGrid, LSPGC, and VPC, Horizon West, based on its reduced return on equity associated with its soft capital cost cap and 15 year annual revenue requirement cap, provides lower present value estimated revenue requirements in the base case analysis as well as in all but the most extreme cases of the sensitivity analyses performed. This is due to Horizon West's lower projected capital costs, O&M costs, and cost of debt. Accordingly, the ISO has determined that Horizon West's proposal is strongest from an estimated revenue requirement and cost containment perspective.

Regarding the proposed costs and cost containment measures of the other four project sponsors for their five proposals, CalGrid's proposal has a robust annual revenue requirement cap, the lowest ROE cap, and the lowest evaluated annual revenue requirements caps across all sensitivities, even after accounting for excluded costs, followed by Lotus' proposal, which provided lower capital costs, an ROE cap for the life of the project, and a capital cost cap that had limited effectiveness due to its many exclusions. Lotus' proposal was followed by the proposals from LSPGC and VPC, which, despite having strong annual revenue requirement caps, included substantially higher estimated costs.

Excluding consideration of any siting-related cap exclusions from the various cost containment measures or any project risk considerations, and accounting for the anticipated lower capital costs of Horizon West's proposal in coordination with its soft capital cost cap and the shorter terms of Horizon West's annual revenue requirement caps, the ISO has determined that Horizon West's proposed cost and cost containment measures are strongest, followed by CalGrid's proposal, Lotus' proposal, LSPGC's proposal, VPC's Dunes proposal inclusive of IID participation only, and then VPC's transmission line only proposal excluding IID participation.

The ISO has determined that the project sponsors' proposed cost cap exclusions cannot be fully compared and evaluated in isolation. They must also be considered in the context of the specific risks each project presents, the likelihood that specific cost cap exclusions might be triggered, and the potential magnitude of impact of any triggered cost cap exclusion. The ISO discusses each project's risk profile in the project risks and mitigation subsection below and then provides a more holistic comparative analysis of the binding cost containment measures, cost cap exclusions, risk profiles, and likelihood of triggering cost cap exclusions in the overall assessment subsection below.

Cost Containment Performance for Past Projects

Regarding completing past projects within the project budget, Horizon West indicated that it had a significantly greater number of projects that were completed at or below budget than the other project sponsors. Those projects had similar capital requirements to this project, and those projects that were completed over budget were an average of 4% greater than the estimates. CalGrid and LSPGC demonstrated a reasonable degree of success in completing projects at or under budget, recognizing that the number of completed projects varied among them but were both significantly less than Horizon West's. Lotus did not provide actual cost information for any of its transmission line projects, and VPC provided cost information only for four projects, out of which three were small projects less than $3 million.

Consequently, the ISO has determined that the proposal of Horizon West is better than the proposals from CalGrid and LSPGC, between which there is no material difference in completing projects on or under budget, and it considers the experience of CalGrid and

LSPGC as represented in their proposals to be better than the experience described by Lotus and VPC, between which the ISO was unable to determine any material difference. In any event, given that all project sponsors proposed specific cost containment measures, those measures would have the most direct bearing on cost containment for this project.

Project Management Capabilities

The ISO determined that all five project sponsors provided a reasonable approach to professional project management for their proposals and, as a result, determined them to be comparable regarding project management capabilities.

Project Risks and Mitigation of Risks

All five project sponsors provided a description of a thorough and professional approach to identifying risks to the completion of the project within the project budget and possible mitigations for those risks for their proposals. All project sponsors submitting applications for more than one project confirmed their ability to work on multiple projects simultaneously, if awarded more than one. VPC indicated that it is submitting proposals for only this project. All five project sponsors have taken steps to reduce risk.

All five project sponsors' proposals identified a variety of similar cost exclusions that were excluded from their respective binding cost containment provisions. Horizon West's proposal was the only proposal that did not exclude additional costs due to route changes that may be required, and it specified more limited types of increases to environmental mitigation costs that would be excluded from its binding cost containment provisions than the proposals of the other project sponsors.

The proposal from Lotus included a number of additional cost exclusions beyond those specified in the proposals of the other project sponsors and indicated that the nominal cost cap provided was for information only and did not include an inflation cap. The proposals from Lotus also indicated that when Lotus files its transmission revenue requirement rate case with FERC prior to the in-service date of the project, the filling submitted would include actual incurred inflation and would seek to demonstrate the prudence of the amount. The ISO considers these representations from Lotus to create an additional risk of cost escalation above Lotus' estimated costs in its proposal beyond the typical exclusions set forth in the proposals of the other project sponsors.

The proposals from CalGrid and Lotus both include routes that cross the Fort Yuma Quechan Tribe Reservation. Rights-of-way acquisition across tribal lands requires additional review and approvals and increases the risk of route changes. Route changes required by a governmental entity were identified by both CalGrid and Lotus as being excluded from their cost cap and cost containment provisions and represent a particular risk of cost escalation for these proposals.

Based on the foregoing analysis, the ISO has determined that regarding project risk and mitigation the proposal from Horizon West is slightly better than proposals of LSPGC and VPC due to the lower number of binding cost cap exclusions identified by Horizon West. The ISO considers LSPGC's proposal and both of VPC's proposals to be better than the proposal from CalGrid, primarily due to the route risk in CalGrid's proposal associated with the Fort Yuma Quechan Tribe rights-of-way acquisition. The ISO considers the proposal from Lotus to present even greater risk of cost escalation than the proposals of the other project sponsors because of its significantly longer route across the Fort Yuma Quechan Reservation, its low cost of debt assumptions, and its many exclusions, including its lack of a cap on inflation.

Overall Assessment

For purposes of the comparative analysis for this component of the factor, the ISO's analysis considered the expected effectiveness of the project sponsor's overall cost containment capabilities, including but not limited to estimated capital costs; cost containment performance on prior projects; project management and scheduling organizations and capabilities; experience of key individuals; the project risk and mitigation that each project sponsor identified; factors affecting cost; and proposed cost containment plans and proposed binding cost caps.

As discussed above and in Section 2.1, the ISO has identified this selection factor as a key selection factor because under ISO Tariff Section 24.5.1 binding cost containment commitments are a key selection factor in every ISO competitive solicitation, and the ISO considers commitment to robust, binding cost containment measures to be the most effective way in which the ISO can ensure that a project is developed in an efficient and cost-effective manner. Consequently, the ISO considers the proposed cost and binding cost containment measures, inclusive of identified exclusions, proposed by project sponsors to be the most significant inputs into the comparative analysis for this component of the factor.

As discussed above, the ISO has determined that the proposals of the five project sponsors are comparable regarding project management capabilities, and that the proposal of Horizon West is better than other proposals regarding cost containment performance on prior projects. The ISO addresses the comparison of project risks and mitigation in conjunction with the analysis of cost containment below.

Horizon West's soft capital cost cap provisions in combination with its lower estimated costs, 15 year annual revenue requirement cap and its low risk profile and limited proposed cost cap exclusions, makes it stronger than all other proposals. The net present value of the projected revenue requirements of Horizon West's proposal is lower than the net present value of the projected revenue requirements of all of the other proposals in all but a few extreme financial sensitivities. Also, Horizon West proposes the least cost cap exclusions of all proposals, and the ISO considers Horizon West's proposal to present less risk of modification or relocation than the proposals from CalGrid and Lotus, which may result in significant cost escalation.

The proposal from Lotus has the least robust cost containment provisions but provides a net present value of revenue requirements that is slightly lower than the net present value of the revenue requirements for the CalGrid proposal. However, the robust cost containment provisions of CalGrid's annual revenue requirement in conjunction with its estimated capital costs, even with the identified route risk concerns, make its proposal stronger than the Lotus proposal primarily due to Lotus' many cost containment exclusions, route and associated cost escalation risk associated with its preferred route, and cost of debt assumptions.

The proposals from LSPGC and VPC provide stronger binding cost cap provisions than the proposal from Lotus. However, Lotus' proposal is stronger than the proposal of LSPGC and both VPC proposals, due to its lower capital cost estimate and cost of debt assumptions that result in lower evaluated net present value of revenue requirement costs for the base case and large majority of financial sensitivity analyses performed.

Comparing LSPGC's proposal with the proposals from VPC, based solely on the proposed cost caps, and accounting for excluded costs, LSPGC's proposal has a slightly lower projected net present value of revenue requirements than both proposals from VPC.

As a result, after applying all of the foregoing considerations included in the ISO's analysis for this component of the factor, the ISO has determined that Horizon West's proposal is better than the five proposals of the other four project sponsors regarding this component, followed in order by CalGrid's proposal, Lotus' proposal, LSPGC's proposal, VPC's Dunes proposal, inclusive of IID participation, and then the VPC transmission line proposal, exclusive of IID participation. Horizon West proposed the lowest estimated capital costs, significant cost containment measures, and the fewest proposed cost cap exclusions, which produced the lowest anticipated projected total revenue requirements.

Comparative Analysis of the Authority to Impose Binding Cost Caps

Because all five project sponsors have proposed binding cost cap provisions for their proposals, in accordance with the provisions of this component of the factor, the ISO has not considered this component of the factor in the comparative analysis.

Overall Comparative Analysis

The ISO considers the first component of this factor (cost containment and cost caps) more important than the second component (siting authority imposing a cost cap). Given that all five project sponsors offered a binding cost cap for each of their proposals, the first component is the only basis for the comparative analysis of this factor.

Based on the ISO's analysis for the first component of this factor discussed above, the ISO has determined that Horizon West's proposal is better than the five proposals of the other four project sponsors regarding this factor, followed in order by CalGrid's proposal, Lotus' proposal, LSPGC's proposal, VPC's Dunes proposal, inclusive of IID participation, and then the VPC transmission line proposal, exclusive of IID participation.

3.13 Selection Factor 24.5.4(k): Additional Strengths or Advantages

(Introduction, A-4, A-5, QP-1, QP-2, Z-1)

The eleventh selection factor is "any other strengths and advantages the Project Sponsor and its team may have to build and own the specific transmission solution, as well as any specific efficiencies or benefits demonstrated in their proposal."

3.13.1 Information Provided by CalGrid

Project Design

CalGrid indicated that the planned construction of its proposed project would utilize steel lattice towers and 1,272 kcmil ACSS (aluminum conductor steel supported) "Bittern" conductor. (A-4)

CalGrid indicated that the transmission line conductor that it is proposing has an ampacity rating of 4,620 A, which is significantly higher than the 2,857 A ampacity rating required by the ISO's Functional Specifications. CalGrid indicated the overall transmission line design would support the conductor's full 4,620 A ampacity. CalGrid indicated that this would include the conductors, structures, hardware, connectors, and other equipment. (Response to Qualification Items)

Other Advantages

Regarding the potential for expansion of the project to accommodate an interconnection with IID, CalGrid indicated it is committed to work with the ISO and IID to evaluate options on any future expansion of its project including a 230 kV connection with the Highline Substation if it is determined to be needed or economic by both parties. CalGrid also indicated that it is committed to the cost containment measures associated with that expansion as outlined in its responses. (Z-1)

3.13.2 Information Provided by Horizon West

Project Design

Horizon West indicated that its proposed project consists of the construction of an 82-mile single-circuit double-bundle 2156 kcmil aluminum conductor steel reinforced (ACSR) conductor (referred to as Bluebird) supported by a combination of lattice guyed-V and tubular steel monopole structures. (A-4)

Horizon West indicated it performed a generation deliverability analysis with both its proposed solution and a reference model provided by the ISO for the current competitive solicitation process. Horizon West indicated that it evaluated the performance of both projects separately to ensure that Horizon West's proposed design not only meets the transmission needs identified by the ISO but also performs comparably to the reference solution developed by the ISO.

Horizon West indicated it performed a reliability assessment utilizing ISO 2022-2023 reliability base cases to ensure that the addition of the project would comply with all applicable standards and would not generate any new system violations. (QP-2)

Horizon West indicated that the transmission line conductor that it is proposing has an ampacity rating of 3,194 A which is higher than the 2,857 A ampacity rating required by the ISO Functional Specifications. (QP-1)

Horizon West indicated the overall transmission line design would support the conductor's full 3,194 A ampacity. Horizon West indicated that this would include the conductors, structures, hardware, connectors, and other equipment. (Response to Qualification Items)

In addition, Horizon West identified a triple-bundle 715 kcmil ACSS (aluminum conductor steel supported) 1 30/19 "Redwing" conductor as a no additional cost option. Horizon

West indicated the Redwing option, which has an ampacity rating of 4,615 A, meets all ampacity, audible noise, corona, and electromagnetic field requirements. (QP-1)

Horizon West indicated the overall transmission line design would support the Redwing conductor's full 4,615 A ampacity. Horizon West indicated that this would include the conductors, structures, hardware, connectors, and other equipment. (Response to Qualification Items)

Other Advantages
Horizon West indicated it is also qualified as a PTO in the ISO. Horizon West indicated its indirect parent, NextEra, is the world's largest electric utility by market capitalization and one of America's largest infrastructure capital investors in any industry and that NextEra companies own and operate more than 12,800 miles of HV transmission lines and nearly 1,200 substations across North America. (A-5)

Horizon West indicated that its affiliate NextEra has an umbrella general liability policy that includes hundreds of millions of dollars of California wildfire specific coverage. Horizon West indicated it has reviewed its coverage with subject matter experts and executives at its affiliate and it provides sufficient coverage in the unlikely event that damages should occur. (Z-1 response to qualification items).

3.13.3 Information Provided by Lotus

Project Design
Lotus indicated that its proposed project consists of the construction of a single circuit 500 kV overhead transmission line traversing approximately 72.5 miles from APS's North Gila Substation to SDG&E's Imperial Valley Substation and would be connected to the existing 500 kV buses between these two substations. Lotus indicated that its proposed transmission line would be supported on a combination of steel monopole, tubular guyed-V, and self-supported lattice towers. (A-4)

Lotus indicated that its project would utilize a TS conductor that it believes would provide an optimal solution for the project because it reduces the number and size of structures due to its light weight. (Z-1)

Lotus indicated that the transmission line conductor that it is proposing has an ampacity rating of 4,346 A, which is significantly higher than the 2,857 A ampacity rating required by the ISO Functional Specifications. Lotus indicated the overall transmission line design would support the conductor's full 4,346 A ampacity. Lotus indicated that this would include the conductors, structures, hardware, connectors, and other equipment. (Response to Qualification Items)

Lotus indicated that its proposed conductor has a high efficiency that reduces traditional line losses and allows a design that reduces the impact to the environment based upon reducing ground disturbance required to support it. (Z-1 Response to Qualification Items)

Other Advantages
Lotus indicated it specializes in deploying equity capital in energy infrastructure investment in North America, with a focus on the transmission, renewable power generation, energy storage, biofuels, and natural gas sectors. (A-5)

Lotus indicated that a subsidiary of Lotus, and the approved project sponsor of the ISO competitively awarded Delaney-Colorado River 500 kV Transmission Line project, also known as Ten West Link, has recent experience developing a 500 kV transmission line in the same region, the experience of which reduces the risk for this project through the application of lessons learned. Lotus indicated that the Ten West Link project is only 53 miles north of the proposed project. Lotus indicated the Ten West Link project is located in similar terrain, interfaced with some of the same utilities with which relationships have been built to collaborate, and provided first-hand recent experience with approvals from some of the same agencies, which contribute to Lotus' experience base and lessons learned. (A-5)

3.13.4 Information Provided by LSPGC

Project Design
LSPGC indicated that its proposed project consists of the construction of an 87-mile overhead transmission line rated at 525 kV with structures that would include lattice guyed-v suspension structures, tubular steel H-frame tangent and small running angle structures, tubular steel monopole tangent, running angle, and dead-end structures. (T-7)

LSPGC indicated that the transmission line conductor that it is proposing has an ampacity rating of 3,489 A, which is higher than the 2,857 A ampacity rating required by the ISO Functional Specifications. (T-8)

LSPGC indicated that all aspects of the proposed project support the proposed higher 3,489 A rating. (Response to Qualification Items).

Other Advantages
LSPGC indicated the project would be implemented by a qualified and experienced team, led by LSPGC, with demonstrated success on similar projects. LSPGC indicated this team completed significant diligence and design work to provide the ISO with best overall value and the most certainty. LSPGC indicated it has ample financial resources to complete the project with a financial assurance from LSPGC to provide sufficient financing for the project. LSPGC indicated it has sufficient cash on hand and available credit facilities to fully fund project implementation with a demonstrated ability to raise debt and equity for construction and long-term financing. (A-4)

LSPGC indicated that its parent, LS Power is a transmission and power generation company that owns and manages one of the most diverse independent transmission and power generation portfolios in the United States, including over 16,000 MW of power generation and 600 miles of high-voltage transmission infrastructure. (A-5)

3.13.5 Information Provided by VPC for the VPC Proposal

Project Design
VPC indicated that its proposed project consists of the construction of a transmission line approximately 83 miles in length, using horizontal double-bundle 2-2156 aluminum conductor steel reinforced (ACSR) 84/19 "Bluebird" conductor and using lattice and tangent monopole support structures. (T-1)

VPC indicated that it has been working for the past ten years studying transmission line routes, and that the proposed route is a result of this study.

VPC indicated that the transmission line conductor that it is proposing has an ampacity rating of 3,246 A, which is higher than the 2,857 A ampacity rating required by the ISO Functional Specifications. (T-7)

VPC indicated the overall transmission line design would support the conductor's full 3,246 A ampacity. VPC indicated that this would include the conductors, structures, hardware, connectors, and other equipment. (Response to Qualification Items)

Other Advantages
VPC indicated the project team has completed extensive stakeholder engagement over the past ten plus years with permitting agencies, tribes, private landowners, local organizations, and other interested parties. (A-4)

VPC included letters of support for the project from several stakeholders. (A-4)

VPC indicated that Grid United is dedicated to developing a portfolio of large-scale interregional transmission projects with the objective of revolutionizing North America's electric grid. (A-5)

VPC indicated the project has been under development for over ten years and has completed the WECC three phase rating process with the added requirement for peer review of all aspects of the local, regional, and NERC and WECC reliability criteria and planning standards. VPC indicated that the project currently has a WECC accepted rating of 1,250 MW, which would increase the transfer capability of Path 46 to a total of 12,450 MW. (QP-2)

VPC indicated Citizens Energy's participation in the project would create benefits for disadvantaged communities in the project area. (Z-1)

VPC indicated that IID has more land acquisition and permitting experience in the project area than any other entity. (Z-1)

VPC indicated it has conducted a thorough routing study for the past ten years of all possible routes and that this gives VPC a high degree of confidence in its selected route. (Z-1 response to Qualification Items).

3.13.6 <u>Information Provided by VPC for the VPC Dunes Proposal</u>

Project Design
VPC indicated that its proposed project consists of the construction of a transmission line approximately 85-miles long, which would be designed using double bundled Bluebird (2156 aluminum conductor steel reinforced (ACSR)) conductors and that the planned tower types are lattice towers on federal land and monopoles through private agricultural land. VPC indicated that the project would also include the construction of a new Dunes 500 kV Switching Station. VPC indicated that the Dunes 500 kV Switching Station is being designed as a ring bus expandable to a breaker and half configuration for future expansion. (QP-1)

VPC indicated that this proposal, including the Dunes 500 kV Switching Station, would best maximize value to the ISO's customers, result in the most system benefits, and best meet the ISO's policy objectives as well as California's broader policy objectives by opening the Imperial Valley's vast renewable resource potential. (A-4)

VPC indicated that its proposal would allow access to in state renewable resources by adding a new Dunes 500 kV Switching Station to its proposed transmission solution that is adjacent to a planned 500/230 kV Dunes Substation that IID intends to construct, own, and operate with a new IID 230 kV transmission line to IID's planned Nelson 230 kV Substation.

VPC indicated that its Dunes 500 kV Switching Station would be strategically located within a BLM solar energy resource zone, near a known geothermal resource area, and close to private lands in eastern Imperial Valley that are suitable for renewable energy development. (A-4)

VPC indicated that the transmission line conductor that it is proposing has an ampacity rating of 3,246 A, which is higher than the 2,857 A ampacity rating required by the ISO Functional Specifications. (T-7)

VPC indicated the overall transmission line design would support the conductor's full 3,246 A ampacity. VPC indicated that this would include the conductors, structures, hardware, connectors, and other equipment. (Response to Qualification Items)

VPC indicated, however, that the limiting factor for its project would be equipment in the new Dunes Switching Station that is rated at 3000 A. (Response to Qualification Items.)

VPC indicated that the inclusion of the Dunes 500 kV Switching Station would serve as an on-ramp for renewables to utilize the additional potential capacity of the transmission line. (A-4)

Other Advantages
VPC indicated that its proposal includes the participation of IID and Citizens Energy and that the project team has completed extensive stakeholder engagement over the past ten plus years with permitting agencies, tribes, private landowners, local organizations, and other interested parties. (A-4)

VPC included letters of support for the project from several stakeholders. (A-4)

VPC indicated that Grid United is dedicated to developing a portfolio of large-scale interregional transmission projects with the objective of revolutionizing North America's electric grid. (A-5)

VPC indicated that the project has been under development for over ten years and has completed the WECC three phase rating process with the added requirement for peer review of all aspects of the local, regional, and NERC and WECC reliability criteria and planning standards. VPC indicated that the project currently has a WECC accepted rating of 1,250 MW, which would increase the transfer capability of Path 46 to a total of 12,450 MW. (QP-2)

VPC indicated Citizens Energy's participation in the project would create benefits for disadvantaged communities in the project area. VPC indicated IID has more land acquisition and permitting experience in the project area than any other entity. (Z-1)

VPC indicated it has conducted a thorough routing study for the past ten years of all possible routes, which gives VPC a high degree of confidence in its selected route. (Z-1 response to Qualification Items).

3.13.7 ISO Comparative Analysis

For the purposes of the comparative analysis for this factor, the ISO has reviewed the six proposals from the five project sponsors to determine if there are advantages the project sponsor or its team have for building and owning the project that were not addressed in other parts of the selection process. This comparative analysis considers proposed project design and other potential advantages.

Project Design

Project design will be considered in two parts, (1) transmission line ampacity and (2) project scope.

Ampacity
The ISO Functional Specifications require projects to provide at a least 2857 A rating. All proposed projects included the use of conductors that had ampacity ratings that exceeded the rating in the ISO Functional Specifications. There were some differences in transmission line ampacity among the submitted proposals ranging from 3194 A to 4620 A and one proposal (by Horizon West) offered an optional conductor at no additional costs that had an even higher ampacity rating. All project sponsors confirmed that their proposed transmission line design would support the higher ampacity ratings proposed. However, the VPC Dunes proposal indicated that its project's overall ampacity rating was lower than the proposed conductor rating due to the ampacity limit imposed by a 3,000 A limitation of its proposed Dunes Switching Station.

The ISO considered the fact that all project sponsors proposed projects with designs that resulted in ampacity ratings that exceeded the ISO's Functional Specifications and determined that there is no material difference among the six proposals regarding the additional ampacity provided because the value of additional ampacity is uncertain at this time, based on the information available to the ISO.

Project Scope

With the exception of the VPC Dunes proposal, all proposals proposed a single transmission line using various types of support structures. In addition to the transmission line, the VPC Dunes proposal also included the construction of a Dunes 500 kV Switching Station. The inclusion of a switching station exceeds the ISO Functional Specifications because the ISO Functional Specifications did not contemplate the addition of a substation to the North Gila to Imperial Valley #2 500 kV line. Based on the information available to the ISO, the value to ISO ratepayers of the addition of the Dunes substation and inclusion of IID and associated allocation of 20% of the transmission line capacity is uncertain at this time. However, this does not preclude the ISO from considering the Dunes substation in another context at a later time.

Other Advantages

VPC's proposals propose the inclusion of Citizens Energy as a potential participant in the project and assert that Citizens Energy's participation in the project would create benefits for disadvantaged communities in the project area. However, ISO notes that the inclusion of Citizens Energy is optional and not guaranteed. Consequently, the ISO is unable to attribute any particular advantage to this aspect of VPC's proposal.

The ISO has determined that none of the project sponsors' proposals identifies any other particular advantage to the ISO and transmission ratepayers that the ISO has not already considered and addressed in the foregoing analysis or its analysis of the more specific selection factors.

Overall Comparative Analysis

As discussed above, the ISO is unable to identify any particular benefit or advantage regarding the additional ampacity of the transmission lines in the six proposals of the five project sponsors. Regarding the VPC Dunes proposal to include a switching station, the ISO considers the potential benefits from this interconnection to IID and associated reduction in ISO capacity on the North Gila to Imperial Valley #2 line due to IID's ownership stake to be uncertain based on the information currently available to the ISO. The ISO is also unable to identify a particular benefit or advantage to the ISO and its ratepayers of VPC's proposed inclusion of Citizens Energy.

The ISO has determined that none of the project sponsors' proposals identifies any other particular advantage to the ISO and transmission ratepayers that the ISO has not already considered and addressed in the foregoing analysis or its analysis of the more specific selection factors. Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the six proposals of the five project sponsors regarding this factor.

3.14 Selection Factor 24.5.4(a): Capability to Finance, License, Construct, Operate, and Maintain the Facility

In this section, the ISO provides the comparative analysis of this selection factor, as discussed in Section 3.3 of this report. This selection factor is a comparative analysis of "the current and expected capabilities of the Project Sponsor and its team to finance, license, and construct the facility and operate and maintain it for the life of the solution." As noted in Section 3.3, this factor encompasses several more specific selection factors, which are discussed in Sections 3.7, 3.8, 3.9, and 3.10 of this report.

What follows is an overall comparative analysis for this factor based upon the discussion of the other factors or factor components encompassed by this factor. As stated in Section 3.3, the ISO will not repeat all of the information provided by the project sponsors for these more specific selection factors and the comparative analysis for each.

In addition to the general project information provided in the project sponsors' proposals, the other selection factors (or components of a factor) considered in the comparative analysis for this factor are as follows:

24.5.4(e): the financial resources of the project sponsor and its team;

24.5.4(f): the technical [environmental permitting] qualifications and experience of the project sponsor and its team (component of 24.5.4(f));

24.5.4(g): the previous record regarding construction and maintenance of transmission facilities, including facilities outside the ISO controlled grid, of the project sponsor and its team; and

24.5.4(h): demonstrated capability to adhere to standardized construction, maintenance, and operating practices of the project sponsor and its team.

3.14.1 ISO Comparative Analysis

The ISO's comparative analysis has considered the results of the analysis of the four selection factors or factor components listed above. As an initial matter, the ISO notes that all of the project sponsors and their teams are capable of satisfying these selection factors regarding this project.

The ISO has determined that Horizon West's proposal is better than the five proposals of the other four project sponsors regarding this factor because, as discussed regarding each of the relevant individual selection factors or factor components, it is better than CalGrid's proposal regarding the third selection factor (construction and maintenance record) and better regarding the fourth selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), it is better or slightly better than LSPGC's proposal regarding the first selection factor (financial resources), the second selection factor component (technical [environmental permitting] qualifications and experience of the project sponsor and its team), the third selection factor, and the fourth selection factor, it is better or slightly better than Lotus' proposal and both of VPC's proposals regarding the first selection factor, the third selection factor, and the fourth selection factor, and there is no material difference among Horizon West's proposal and the five proposals of the other four project sponsors regarding the other relevant selection factors or factor components.

The ISO has determined that CalGrid's proposal is slightly better than the proposals of VPC, Lotus, and LSPGC regarding this factor because, as discussed regarding each of the relevant individual selection factors or factor components, it is better than VPC's two proposals regarding the first selection factor, it is better than Lotus' proposal regarding the first selection factor, and slightly better regarding the third selection factor, and it is better than LSPGC's proposal regarding the first selection factor and slightly better regarding the second selection factor component and the third selection factor, and LSPGC's proposal is better than CalGrid's proposal regarding the fourth selection factor, which the ISO considers to result in a slight advantage for CalGrid's proposal, and there is no material difference among CalGrid's proposal and the proposals of VPC, Lotus, and LSPGC regarding the other relevant selection factors or factor components.

The ISO has determined that LSPGC's proposal is slightly better than Lotus' proposal and VPC's two proposals because, as discussed regarding each of the relevant individual selection factors or factor components, it is slightly better than Lotus' proposal regarding the first selection factor, and it is better than Lotus' proposal regarding the fourth selection factor, and Lotus' proposal is slightly better than LSPGC's proposal regarding the second selection factor component, and there is no material difference between LSPGC's proposal and Lotus' proposal regarding the third selection factor, which the ISO considers to result in a slight advantage for LSPGC's proposal, and LSPGC's proposal is slightly better than VPC's proposals regarding the first selection factor and better regarding the fourth selection factor, and VPC's proposals are slightly better than LSPGC's proposal regarding the second selection factor component and the third selection factor, which the ISO considers to result in a slight advantage for LSPGC's proposal.

The ISO has determined that there is no material difference between the two proposals of VPC regarding this factor because, as discussed regarding each of the relevant individual selection factors or factor components, there is no material difference between them regarding any of the relevant factors or factor components. The ISO has determined that VPC's two proposals are slightly better than Lotus' proposal because, as discussed regarding each of the relevant individual selection factors or factor components, VPC's proposals are slightly better than Lotus' proposal regarding the third selection factor, and there is no material difference among VPC's proposals and Lotus' proposal regarding the first selection factor, the second selection factor component, and the fourth selection factor.

In summary, based on a detailed review of the proposals of the project sponsors regarding these individual selection factors and factor components, the ISO has determined that Horizon West's proposal is better than CalGrid's proposal, which is slightly better than LSPGC's proposal, which is slightly better than VPC's two proposals, which are slightly better than Lotus' proposal, regarding this factor overall.

3.15 Qualification Criterion 24.5.3.1(a): Manpower, Equipment, and Knowledge to Design, Construct, Operate, and Maintain the Project

The first qualification criterion is "whether the Project Sponsor has demonstrated that it has assembled, or has a plan to assemble, a sufficiently-sized team with the manpower, equipment, knowledge and skill required to undertake the design, construction, operation and maintenance of the transmission solution."

The first qualification criterion is a broad criterion that encompasses three specific selection factors that are discussed in Sections 3.8, 3.9, and 3.10 of this report. The ISO will not repeat here the information provided by the project sponsors for these more specific selection factors or the comparative analysis for each. What follows is an overall comparative analysis for this criterion based upon the comparative analyses for the selection factors encompassed by this criterion.

3.15.1 ISO Comparative Analysis

The ISO previously determined and posted notice on its website that all six proposal submitted by the five project sponsors meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion considers several factors addressed by the selection factors previously discussed. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factors addressed above. The selection factors or factor components considered in the comparative analysis for this criterion are as follows:

> 24.5.4(f): the engineering qualifications and experience of the project sponsor and its team (a component of 24.5.4(f));
>
> 24.5.4(g): the previous record regarding construction and maintenance of transmission facilities, including facilities outside the ISO controlled grid, of the project sponsor and its team; and
>
> 24.5.4(h): demonstrated capability to adhere to standardized construction, maintenance, and operating practices, of the project sponsor and its team.

The ISO's comparative analysis has considered the results of the analysis of the three selection factors or factor components listed above. As an initial matter, the ISO notes that all of the project sponsors and their teams are capable of satisfying these factors regarding this project. The ISO has determined that Horizon West's proposal is slightly better than the five proposals of the other four project sponsors regarding this criterion because, as discussed regarding each of the relevant individual selection factors or factor components, it is slightly better than the proposals of CalGrid, Lotus, and VPC regarding the second selection factor (construction and maintenance record) and better regarding the third selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), and the proposals of CalGrid, Lotus, and VPC are better than Horizon West's proposal regarding the first selection factor component (engineering qualifications and experience of the project sponsor and its team), which in comparison to the advantages of Horizon West regarding the second selection factor and the third selection factor still results in a slight advantage for Horizon West's proposal over the proposals of CalGrid, Lotus, and VPC, and it is better or slightly better than LSPGC's proposal regarding the first selection factor component, the second selection factor, and the third selection factor.

The ISO has determined that there is no material difference among CalGrid's proposal and the two proposals of VPC regarding this factor because, as discussed regarding each of the relevant individual selection factors or factor components, there is no material difference among them regarding any of the relevant factors or factor components.

The ISO has determined that CalGrid's proposal and the two proposals of VPC are slightly better than the proposals of Lotus and LSPGC regarding this factor because, as discussed regarding each of the relevant individual selection factors or factor components, they are slightly better than Lotus' proposal regarding the second selection factor, and there is no material difference among the proposals of CalGrid, Lotus, and VPC regarding the first selection factor component and the third selection factor, and the proposals of CalGrid and VPC are better than LSPGC's proposal regarding the first selection factor component and slightly better regarding the second selection factor, and LSPGC's proposal is better than the proposals of CalGrid and VPC regarding the third selection factor, which the ISO considers to result in a slight advantage for the proposals of CalGrid and VPC's proposal.

The ISO has determined that there is no material difference between Lotus' proposal and LSPGC's proposal because, as discussed regarding each of the relevant individual selection factors or factor components, Lotus' proposal is better than LSPGC's proposal regarding the first selection factor component, LSPGC's proposal is better than Lotus' proposal regarding the third selection factor, and there is no material difference between LSPGC's proposal and Lotus' proposal regarding the second selection factor which the ISO considers to result in offsetting advantages for Lotus' and LSPGC's proposals.

In summary, based on a detailed review of the proposals of the project sponsors regarding these individual selection factors and factor components, the ISO has determined that Horizon West's proposal is slightly better than CalGrid's proposal and the two proposals of VPC, among which there is no material difference, which are slightly better than the proposals of Lotus and LSPGC, between which there is no material difference, regarding this criterion overall.

3.16 Qualification Criterion 24.5.3.1(b): Financial Resources

The second qualification criterion is "whether the Project Sponsor and its team have demonstrated that they have sufficient financial resources, by providing information including, but not limited to, satisfactory credit ratings, audited financial statements, or other financial indicators."

3.16.1 <u>ISO Comparative Analysis</u>

The ISO previously determined and posted notice on its website that all six proposals submitted by the five project sponsors meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion essentially duplicates the factors addressed by selection factor 24.5.4(e) (the financial resources of the project sponsor and its team) discussed in Section 3.7 above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factor above. As discussed above regarding selection factor 24.5.4(e), the ISO has determined that there is no material difference between CalGrid and its proposal and Horizon West and its proposal, and they are better than LSPGC and its proposal, which is slightly better than Lotus and its proposal and VPC and its two proposals, among which there is no material difference regarding this criterion.

3.17 Qualification Criterion 24.5.3.1(c): Ability to Assume Liability for Losses

The third qualification criterion is "whether the Project Sponsor and its team have demonstrated the ability to assume liability for major losses resulting from failure of any part of the facilities associated with the transmission solution by providing information such as letters of credit, letters of interest from financial institutions regarding financial commitment to support the Project Sponsor, insurance policies or the ability to obtain insurance to cover such losses, the use of account set asides or accumulated funds, the revenues earned from the transmission solution, sufficient credit ratings, contingency financing, or other evidence showing sufficient financial ability to cover these losses in the normal course of business."

3.17.1 ISO Comparative Analysis

The ISO previously determined and posted notice on its website that all six proposals submitted by the five project sponsors meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion essentially duplicates the factors addressed by selection factor 24.5.4(i) (demonstrated ability to assume liability for major losses resulting from failure of facilities of the project sponsor) discussed in Section 3.11 above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factor above. As discussed above regarding selection factor 24.5.4(i), the ISO has determined that the proposal of Horizon West is better than the proposals of CalGrid and LSPGC, between which there are offsetting strengths and weaknesses resulting in a conclusion that there is no material difference, which are better than the proposal of Lotus, which is slightly better than the two proposals of VPC, regarding this criterion.

3.18 Qualification Criterion 24.5.3.1(d): Proposed Schedule and Ability to Meet Schedule

The fourth qualification criterion is “whether the Project Sponsor has (1) proposed a schedule for development and completion of the transmission solution consistent with need date identified by the ISO; and (2) has the ability to meet that schedule.”

3.18.1 ISO Comparative Analysis

The ISO previously determined and posted notice on its website that all six proposal submitted by the five project sponsors meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion essentially duplicates the factors addressed by selection factor 24.5.4(d) (the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet that schedule of the project sponsor and its team) discussed in Section 3.6 above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factor above. As discussed above regarding selection factor 24.5.4(d), the ISO has determined that, based on the specific scope of this project, that there is no material difference among the proposals of CalGrid, Horizon West, and LSPGC, which are slightly better than the two proposals of VPC, between which there is no material difference, and which are slightly better than the proposal of Lotus, regarding this criterion.

3.19 Qualification Criterion 24.5.3.1(e): Technical and Engineering Qualifications and Experience

The fifth qualification criterion is "whether the Project Sponsor and its team have the necessary technical and engineering qualifications and experience to undertake the design, construction, operation and maintenance of the transmission solution."

3.19.1 ISO Comparative Analysis

The ISO previously determined and posted notice on its website that all six proposals submitted by the five project sponsors meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion considers several factors addressed by the selection factors previously discussed in Sections 3.8, 3.9, and 3.10 above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factors addressed above. The selection factors considered in the comparative analysis for this criterion are as follows:

> 24.5.4(f): the technical [environmental permitting] and engineering qualifications and experience of the project sponsor and its team;
>
> 24.5.4(g): the previous record regarding construction and maintenance of transmission facilities, including facilities outside the ISO controlled grid, of the project sponsor and its team; and
>
> 24.5.4(h): demonstrated capability to adhere to standardized construction, maintenance, and operating practices of the project sponsor and its team.

The ISO's comparative analysis has considered the results of the analysis of the three selection factors listed above. As an initial matter, the ISO notes that all of the project sponsors and their teams are capable of satisfying these selection factors regarding this project. The ISO has determined that Horizon West's proposal is slightly better than the five proposals of the other four project sponsors regarding this criterion because, as discussed regarding each of the relevant individual selection factors or factor components, it is slightly better than the proposals of CalGrid, Lotus, and VPC regarding the second selection factor (construction and maintenance record) and better regarding the third selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), and the proposals of CalGrid, Lotus, and VPC are better than Horizon West's proposal regarding the first selection factor (technical [environmental permitting] and engineering qualifications and experience of the project sponsor and its team), which the ISO considers to result in a slight advantage for Horizon West's proposal over the proposals of CalGrid, Lotus, and VPC, and it is slightly better than LSPGC's proposal regarding the first selection factor, the second selection factor, and the third selection factor.

The ISO has determined that there is no material difference among CalGrid's proposal and the two proposals of VPC regarding this factor because, as discussed regarding each of the relevant individual selection factors, there is no material difference among them regarding any of the relevant factors.

The ISO has determined that CalGrid's proposal and the two proposals of VPC are slightly better than the proposals of Lotus and LSPGC regarding this factor because, as discussed regarding each of the relevant individual selection factors, they are slightly better than Lotus' proposal regarding the second selection factor, and there is no material difference among the proposals of CalGrid, Lotus, and VPC regarding the first selection factor and the third selection factor, and the proposals of CalGrid and VPC are better than LSPGC's proposal regarding the first selection factor and slightly better regarding the second selection factor, and LSPGC's proposal is better than the proposals of CalGrid and VPC regarding the third selection factor, which the ISO considers to result in a slight advantage for the proposals of CalGrid and VPC's proposal.

The ISO has determined that there is no material difference between Lotus' proposal LSPGC's proposal because, as discussed regarding each of the relevant individual selection factors, Lotus' proposal is better than LSPGC's proposal regarding the first selection factor, LSPGC's proposal is better than Lotus' proposal regarding the third selection factor, and there is no material difference between LSPGC's proposal and Lotus' proposal regarding the second selection factor, which the ISO considers to result in offsetting advantages for Lotus' and LSPGC's proposals.

In summary, based on a detailed review of the proposals of the project sponsors regarding these individual selection factors, the ISO has determined that Horizon West's proposal is slightly better than CalGrid's proposal and the two proposals of VPC, among which there is no material difference, which are slightly better than the proposals of Lotus and LSPGC, between which there is no material difference, regarding this criterion overall.

3.20 Qualification Criterion 24.5.3.1(f): Commitment to Enter Into TCA and Adhere to Applicable Reliability Criteria

(A-6)

The sixth qualification criterion is "whether the Project Sponsor makes a commitment to become a Participating TO for the purpose of turning the Regional Transmission Facility that the Project Sponsor is selected to construct and own as a result of the competitive solicitation process over to the ISO's Operational Control, to enter into the Transmission Control Agreement with respect to the transmission solution, to adhere to all Applicable Reliability Criteria and to comply with NERC registration requirements and NERC and WECC standards, where applicable."

3.20.1 Information Provided by CalGrid

CalGrid indicated that it commits to become a participating transmission owner for the purpose of turning the transmission elements included in the project over to the ISO's operational control. CalGrid further indicated that it commits to enter into the TCA for the project transmission elements and to adhere to all applicable reliability criteria and to comply with NERC registration requirements and WECC standards, where applicable. (A-6)

3.20.2 Information Provided by Horizon West

Horizon West indicated that if selected by the ISO as the approved project sponsor for the project, Horizon West, which is already a PTO, commits to turn over the transmission element to the ISO's operational control, to enter into the TCA regarding the transmission element, to adhere to all applicable reliability criteria, and to comply with NERC registration requirements and NERC and WECC standards, where applicable. (A-6)

3.20.3 Information Provided by Lotus

Lotus indicated that it commits as follows:

(1) That the project special purpose entity that would be incorporated for this project would become a PTO with the ISO for the purpose of turning its project over to the ISO's operational control;

(2) That the special purpose entity would negotiate, execute, and abide by the Approved Project Sponsor Agreement with the ISO and would support its filing of this document with FERC, to the extent FERC approval is necessary;

(3) That the special purpose entity would negotiate, execute, and abide by the TCA applicable to its project as well as any provisions of the ISO's tariffs that pertain to a PTO; and

(4) That the special purpose entity would adhere to all applicable reliability criteria (including applicable CIP standards) and would comply with NERC registration requirements and NERC and WECC standards, where applicable.

Lotus indicated that it is not aware of any encumbrances or entitlements that would be identified in its application to become a PTO with the ISO, and all the new transmission capacity associated with its project should be available for use by the ISO customers as of the in-service date. To the extent any encumbrances, entitlements and specific local and all applicable reliability standards apply and arise as the special purpose entity moves the project through development and construction, Lotus indicated that the special purpose entity would work with the ISO to establish an operation plan that ensures seamless treatment. (A-6)

3.20.4 Information Provided by LSPGC

LSPGC indicated that it would become a PTO in 2025 related to the Orchard STATCOM and Fern Road GIS/STATCOM projects. If selected as the approved project sponsor of the project, in accordance with the Approved Project Sponsor Agreement, LSPGC would turn the project over to the ISO's operational control and work with ISO to amend the existing TCA. LSPGC indicated that it would adhere to all applicable reliability criteria and comply with applicable NERC registration requirements and NERC and WECC standards. (A-6)

3.20.5 Information Provided by VPC

VPC indicated that it would execute the TCA and would be a PTO under the ISO Tariff, procedures, and manuals.

VPC indicated that upon initiation of precommercial testing, operational control over its project's transmission facilities would be transferred to the ISO, with such facilities residing within the ISO balancing authority area.

VPC indicated that this transfer of operational control would be conditioned upon ISO's recognition of IID's Transmission Ownership Rights to 20% of the transmission line capacity of the eastern segment of the project – specifically, an approximately 53.5 mile segment between and including structure 195 and the dead-end tower located at the eastern endpoint of the transmission line just outside the existing North Gila 500 kV Substation as well as the corresponding treatment of IID as a non-PTO in accordance with applicable provisions of the ISO Tariff, including Article 17 and related ISO Business Practice Manuals and applicable ISO procedures.

VPC indicated that IID would be a non-PTO and, accordingly, would coordinate with the ISO pursuant to Article 17 of the ISO Tariff and applicable ISO procedures, including but not limited to the issuance of TRTC instructions.

VPC indicated that its project would be owned, operated, and maintained in a manner consistent with Good Utility Practice, as such term is defined in the ISO Tariff, and subject to compliance with all applicable reliability standards. VPC indicated that it would register with NERC and WECC as the Transmission Owner and Transmission Planner. VPC indicated that it has a proposal services agreement in place for its operations contractor to provide designated TOP registration and footprint expansion certification services for the project's transmission facilities. VPC indicated that negotiation and execution of a bilateral contract for the project sponsor's TOP registration and related services would occur after the ISO's award. (A-6)

3.20.6 <u>Information provided by VPC for VPC Dunes</u>

VPC indicated that it would execute the TCA and would be a PTO under the ISO Tariff, procedures, and manuals.

VPC indicated that upon initiation of precommercial testing, operational control over the project's transmission facilities would be transferred to the ISO, with such facilities residing within the ISO balancing authority area.

VPC indicated that this transfer of operational control would be conditioned upon ISO's recognition of IID's Transmission Ownership Rights to 20% of the Dunes to North Gila 500 kV transmission line capacity and 40% of the Dunes 500 kV Switching Station capacity as well as the corresponding treatment of IID as a non-PTO in accordance with applicable provisions of the ISO Tariff, including Article 17 and related ISO Business Practice Manuals and applicable ISO procedures.

VPC indicated that IID would be a non-PTO and, accordingly, would coordinate with the ISO pursuant to Article 17 of the ISO Tariff and applicable ISO procedures, including but not limited to the issuance of TRTC instructions.

VPC indicated that its project would be owned, operated, and maintained in a manner consistent with Good Utility Practice, as such term is defined in the ISO Tariff, and subject to compliance with all applicable reliability standards. VPC indicated that it would register with NERC and WECC as the Transmission Owner and Transmission Planner. VPC indicated that it has a proposal services agreement in place for its operations contractor to provide designated TOP and footprint expansion certification services for the project's transmission facilities. VPC indicated that negotiation and execution of a bilateral contract for the project sponsor's TOP registration and related services would occur after the ISO's award. (A-6)

3.20.7 ISO Comparative Analysis

The ISO previously determined and posted notice on its website that all six proposals submitted by the five project sponsors meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the proposals with regard to the project sponsor qualification criteria in its comparative analysis for purposes of selection of the approved project sponsor.

All five project sponsors, with certain identified limitations in the case of VPC, have committed to becoming a PTO, turning over operational control of the project to the ISO, abiding by the terms of the TCA, and adhering to all applicable reliability criteria for their proposals. Consequently, the ISO has determined there is no material difference among the proposals of the five project sponsors regarding this criterion.

The ISO notes that the VPC and VPC Dunes proposed their transfer of operational control would be conditioned upon ISO's recognition of IID's certain Transmission Ownership Rights as well as the corresponding treatment of IID as a non-PTO in accordance with applicable provisions of the ISO Tariff. The ISO considers this proposal acceptable pursuant to the ISO's competitive solicitation process.

3.21 ISO Overall Comparative Analysis for Approved Project Sponsor Selection

Under ISO Tariff Section 24.5.4, the ISO conducts a comparative analysis to select an approved project sponsor. In accordance with Section 24.5.4, the purpose of the comparative analysis is to take into account all transmission solutions being proposed by competing project sponsors and to select a qualified project sponsor that is best able to design, finance, license, construct, maintain, and operate the particular transmission facility in a cost-effective, efficient, prudent, reliable, and capable manner over the lifetime of the facility, while maximizing the overall benefits and minimizing the risk of untimely project completion, project abandonment, and future reliability, operational, and other relevant problems, consistent with good utility practice, applicable reliability criteria, and ISO documents. In conducting the comparative analysis, the ISO applies the qualification criteria described in ISO Tariff Section 24.5.3.1 and the selection factors specified in Section 24.5.4.

As discussed above, the ISO has conducted this competitive solicitation because, in its 2022-2023 transmission planning process, the ISO identified a policy-driven need for the North Gila-Imperial Valley #2 500 kV Line project. As required by the ISO Tariff, the ISO undertook a comparative analysis to determine the degree to which each project sponsor and its proposal(s) met the applicable tariff selection factors and qualification criteria to determine the approved project sponsor to finance, construct, own, operate, and maintain this project.

The ISO's analysis determined that there are either no material differences or only slight differences among the project sponsors and their proposals regarding many of the selection factors and qualification criteria.

One of the key selection factors for which the ISO identified material differences among the project sponsors' proposals is the estimated cost and cost containment factor, including the project sponsors' commitment to binding cost containment measures. As discussed above, this factor is one of the six key selection factors identified by the ISO at the outset of this competitive solicitation process. Horizon West proposed the lowest estimated capital costs, significant cost containment measures, and the fewest proposed cost cap exclusions, which produced the lowest anticipated projected total revenue requirements at the lowest evaluated risk to ISO ratepayers.

A second key selection factor is the project sponsor's existing rights-of-way and substations that would contribute to the transmission solution in question. As discussed above, the ISO found there were no material differences among the proposals of the project sponsors regarding satisfaction of this factor. No project sponsor has existing land rights along the proposed route, and all project sponsors had sufficient plans for acquiring the necessary land rights.

A third key selection factor is the experience of the project sponsor and its team in acquiring rights-of-way, if necessary, that would facilitate approval and construction, and in the case of a project sponsor with existing rights-of-way, whether the project sponsor would incur costs in connection with placing new or additional facilities associated with the transmission solution on such existing rights-of-way. Again, no project sponsor has existing land rights along the proposed route, and for this selection factor, the ISO determined that Horizon West and CalGrid had the strongest proposals, based on the greater land rights acquisition experience of their teams, including experience acquiring land rights in California.

A fourth key selection factor is the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet the schedule of the project sponsor and its team. The ISO determined that Horizon West, CalGrid, and LSPGC had similarly strong proposals that were stronger than VPC's and Lotus' proposals regarding this factor. Horizon West's proposed schedule provided a substantial amount of cushion in meeting the June 1, 2032 latest in-service date in the ISO Functional Specifications. Horizon West's proposal also included an incentive penalty for failure to meet the latest ISO in-service date. Horizon West's proposal showed that it has a solid track record in timely completing projects and can complete this project and any other project for which it might be selected as the approved project sponsor in a timely manner. These features of Horizon West's proposal combined to make it comparable to, or better than, the other project sponsors' proposals regarding this key selection factor.

The fifth key selection factor is the financial resources of the project sponsor and its team. The ISO's analysis showed that CalGrid and Horizon West have comparable financial metrics and that they are better than Lotus, LSPGC, or VPC in this regard. Horizon West's proposal demonstrated it has substantial financing experience, financial resources, and financial backing sufficient to finance this project along with any other project for which it might be selected as the approved project sponsor.

The sixth key selection factor is the technical and engineering qualifications and experience of the project sponsor and its team. The ISO's analysis showed that Horizon West's environmental permitting team has as much or more relevant experience as any other project sponsor and its team but that the teams of CalGrid, Lotus, and VPC have more experience than Horizon West's team with the design and engineering of EHV transmission projects in California. However, Horizon West's proposal demonstrated it and its team have sufficient experience with the design and engineering of EHV transmission projects to ensure that they are fully capable of performing the design and engineering of this project. The advantage of CalGrid, Lotus, and VPC regarding this selection factor does not offset the significant advantage of Horizon West's cost and cost containment proposal and the overall advantage of Horizon West regarding the other key selection factors.

Regarding the non-key selection factors, Horizon West's proposal was either as strong as or better than the proposals of the other project sponsors for every selection factor. And regarding the six qualification criteria, Horizon West's proposal was as strong as or better than the proposals of the other project sponsors for all six of these criteria.

For the foregoing reasons, the ISO determined that Horizon West and its team are qualified, experienced, and have the financial resources to capably, cost-effectively, and reliably license, finance, construct, operate, and maintain this particular project at the lowest cost and by the specified in-service date. Based on the ISO's review of the proposals and a comparative analysis regarding all of the selection factors and qualification criteria, the ISO determined that Horizon West's proposal is better than the proposals of CalGrid, Lotus, LSPGC, and VPC regarding this project. The result of this competitive solicitation is that the ISO selected Horizon West as the approved project sponsor to finance, construct, own, operate, and maintain the North Gila-Imperial Valley #2 Line project.[9]

[9] Selection of Horizon West as the approved project sponsor does not preclude the ISO from taking positions on specific rate proposals contained in Horizon West's rate filing at FERC regarding its proposal.

Attachment 1

Competitive Solicitation Transmission Project Sponsor Application

Transmission Project Sponsor Proposal –Competitive Solicitation Application

Contents

INTRODUCTION AND GENERAL INSTRUCTIONS

In accordance with ISO Tariff Section 24.5 (Transmission Planning Process Phase 3), the ISO will initiate a period of at least ten (10) weeks that will provide an opportunity for project sponsors to submit specific transmission project proposals to finance, construct, own, operate, and maintain certain transmission elements identified in the ISO's comprehensive transmission plan, or those approved by ISO management in advance of the issuance of the transmission plan if the capital cost of the project is less than or equal to $50 million. Such project proposals must include plan of service details and supporting information as set forth in the Business Practice Manual for the Transmission Planning Process (BPM-TPP) sufficient to enable the ISO to determine whether the proposal meets the criteria specified in ISO Tariff Sections 24.5.3 and 24.5.4. This competitive solicitation application form describes the details that must be provided regarding project sponsor proposals.

Projects included in this process will become part of the ISO controlled grid, and approved project sponsors will become participating transmission owners (PTOs) and will sign the Transmission Control Agreement (TCA) and enter into a Coordinated Functional Registration (CFR) agreement with the ISO. The ISO also anticipates that the project sponsor or its contracted representative(s) will be registered with the North American Electric Reliability Corporation (NERC) in the NERC categories of Transmission Owner and other functions as applicable.

This section sets forth requirements for the formatting and general contents of the project sponsor's application. The application submitted to the ISO shall not include any substantive information in response to this section. In particular, in Section 1 of the application, the project sponsor shall provide a summary of the most significant aspects of the project as proposed by the project sponsor. The ISO will refer to the information provided in Section 1, rather than any information provided in a transmittal letter for an introduction to and overview of the project. The information to be included in the application will be used by the ISO to determine whether the proposal meets the qualification criteria set forth in ISO Tariff section 24.5.3 and, if so, to compare each project sponsor and its proposal with other qualified project sponsors and proposals for the same approved transmission element pursuant to ISO Tariff section 24.5.4. To facilitate this assessment and comparison, project sponsors must provide information that reflects a thorough understanding of the requirements, processes, and activities needed to accomplish project completion and continuing operation and maintenance.

The project sponsor must submit three documents in connection with its proposal:

1. this Competitive Solicitation Application form;
2. the Cost and Cost Containment Workbook;
3. the Prior Projects and Experience Workbook.

The first document, Competitive Solicitation Application, is a completed form of this Microsoft Word document. The second document, Cost and Cost Containment Workbook, is in the form of an Excel spreadsheet. The spreadsheet documents the project sponsor's proposed capital and operations and maintenance (O&M) expenses, and also any proposed cost containment measures. The third document, Prior Projects and Experience Workbook, is in the form of a separate Excel spreadsheet. The spreadsheet documents the project sponsor's listing of prior projects and experience relevant to its capability to develop the current project. Please note that only applicant and contractor experience identified in the Prior Projects and Experience Workbook will used to evaluate past project performance and experience. Experience identified within other areas of sponsor proposals must be included within the Prior Projects and Experience Workbook to be evaluated.

This application form is separated into specific sections. Each section specifies information to be provided and is assigned a unique identifier for each item of information required, for example, QP–1 for Project Qualification, E-1 for Environmental Permitting and Public Processes items, S-1 for items related to Substation Design and Engineering, and so on. Project sponsors must provide responses to each of the items in the space provided after the specification of the information required and clearly note in the response the unique item identifier in each part of the response.

If the project sponsor believes that any item of the application is not applicable to its project proposal, it may indicate "N/A" but must provide a brief reason why it believes it is not applicable.

If supporting documentation is provided to supplement specific responses to application items, the project sponsor must include a specific reference to the item number and to the page numbers and paragraphs of the supporting documentation that are responsive to the application item, along with a brief explanation of how the referenced material is responsive. Information that responds directly to the information requests in the application shall be incorporated directly into the application and not be submitted as separate attachments merely referenced in the application response.

If a project sponsor provides attachments as part of the response, the project sponsor shall specify the file name of the attachment in the space provided for the response. In addition, the project sponsor shall name the attached files using the following naming convention – the file name shall include the unique identifier for the application item to which the information responds (e.g., A-5) and a description of the contents (e.g., A-5 Resumes of Key Individuals). All responses must be in readable electronic format and include the name of the project sponsor and description of the project. When submitting attachments, do **NOT** create any subdirectories. The ISO's filing system cannot process subdirectories and their use may cause important information to be lost. Also, do not use any of the following (special) characters when naming attachment files: [(~ # % & * { } \ / : < > ?)]. Use of any of these special characters is not compatible with the ISO's filing system and will cause important information to be lost. In addition, the project sponsor shall include in its cover letter a table or index in Microsoft Word format that contains a list of documents and attachments provided. The table or index must include the file name, contents, and a description of the application section(s) and items to which it corresponds. The project sponsor must provide a copy of the application in Microsoft Word format. The project sponsor must provide all responses and attached material in English or the ISO will disregard the information submitted.

The following instructions in italics pertain to the submission of geographic information:

*When submitting geographic information, e.g., the proposed route for a transmission line or the location of a proposed new substation, or reactive support or series compensation station, the project sponsor shall provide the information both in a PDF file or files, and also in shapefiles. In order to provide for the greatest support and exchangeability, shapefiles are chosen as the GIS format for submittal. There shall be one shapefile for each proposed transmission project, and no shapefile submitted shall contain more than one proposed transmission project. The proposed transmission projects are to be defined as **line** shapes. The attribute table of the shapefile shall include a **"NAME" text field** that contains the name of the transmission project. This submittal shall include, at a minimum, the following four files: **name.shp**, **name.shx**, **name.dbf** and **name.prj**. The file name shall be the name of the transmission project with any spaces and special characters replaced by underscores or other regular characters. Abbreviating and shortening of the names are acceptable and encouraged. All of the files that make up the shapefile shall be zipped together in a single "zip" file with the same name as the shapefile.*

If the project sponsor proposes to contract with others to perform duties related to the proposed project, the project sponsor's responses to the items in the application must reflect the roles, responsibilities, processes, and procedures to be used by the organization that will perform those duties, and the management controls that will be used by the project sponsor to assure that the work is done in accordance with applicable agreements, contracts, and regulatory and reliability requirements. In addition, the project sponsor shall complete the Excel spreadsheet entitled Prior Projects and Experience Workbook by which the project sponsor is to provide information regarding relevant prior projects and experience of the project sponsor and its contractors.
For each item in the application, if the project sponsor is proposing to finance, construct, own, operate, and maintain multiple transmission elements, the project sponsor shall also indicate how its response would change depending on how many of its proposals are approved by the ISO. For example, in P-4 of Section 4 (Project Management and Schedule) the project sponsor shall describe how the projected in-service date of a project would be affected if two or more of the project sponsor's proposals are approved.

Please note that the ISO will consider only ONE proposal per application submitted. The project sponsor may identify alternate proposals that it has considered, but shall clearly identify the single proposal that it wishes the ISO to evaluate.

This application form includes an officer certification form (Section 15) that must be signed by an officer of the authorized representative of the applicant project sponsor. The ISO will not consider any application that does not include a completed officer certification form.

To the extent a project sponsor considers any of the information submitted with its application to be confidential or proprietary, the project sponsor must clearly identify the confidential or proprietary information and must include an explanation as to why the information should be treated by the ISO as confidential. The ISO will not treat the identity of a project sponsor and basic information about the project sponsor's proposed project as confidential information. A project sponsor must separately request confidential treatment for each response to an individual application information request and explain the need for confidential treatment. Project sponsors shall not make general designations of large sections of the application as confidential or proprietary.

Project sponsors should note that the maximum size of an e-mail submitted to the ISO must not exceed 20 MB or the ISO's e-mail system may not be able to process it. An application that includes files or attachments larger than 20 MB must be compressed to files of a size less than 20 MB. Project sponsors shall submit their information via CD or DVD medium. Please provide 3 complete sets of CDs or DVDs and clearly label each with project name and sponsor name. The ISO prefers that project sponsors submit the initial application (consisting of the Microsoft Word document and associated attachments, and the Excel spreadsheets) on CDs or DVDs.
If a project sponsor wishes to apply for more than one project eligible for the ISO's transmission procurement process, the project sponsor must submit a separate application for each project. Again, the ISO will consider only one proposal per application.
Please note that there are several tables in this application form for use in providing responses. Project sponsors may add rows to the tables if the number of entries exceeds the number of rows initially provided in the tables.

The ISO requires a deposit of $100,000* for each submitted application. The ISO will not consider applications if the project sponsor fails to include the deposit on or before the date the bid window closes. Payment instructions and a project sponsor deposit form can be found in Section 16 of this application form.

While the competitive bid window is open, a project sponsor may submit questions to the ISO for clarification. Questions must be submitted via e-mail to the following address: transmissioncompetitivesolicitation@caiso.com. The ISO will attempt to answer these questions in a timely manner. The answers will be made available in a table that the ISO will post to its website on the "Transmission Planning" page. Note that the ISO will not include the identity of the project sponsor in the table. In general, the ISO will update this table on a weekly basis or as needed.

1 Project Sponsor Name, Organizational Structure, and Proposal Summary

A-1 Project Sponsor Name:

Response: (Enter Project Sponsor Company Name)

A-2 Proposal Name:

Response: (Enter Proposal Name)

A-3 Submittal Date:

Response: (Enter Submittal Date)

A-4 Provide a brief summary of the project sponsor's proposal:

*Re*sponse:

A-5 Provide an organizational chart depicting the project team and areas of responsibility, including the responsibilities of all contractors. In addition, provide a corporate organizational chart of the project sponsor and any parent companies and affiliates. Attach resumes of all key management and lead personnel of the project sponsor, affiliates, and contractors who will be used for the project, including a resume for each lead individual of the project sponsor and its contractors in each area of responsibility for the project. Identify any parent organization or affiliate personnel responsible for a specific project listed in the Prior Projects and Experience Workbook who will be part of the project sponsor's team for the instant project. For project sponsor and affiliated personnel and for contractor personnel, relate each resume to a position on the organization chart provided. The project sponsor should be aware that if it is selected as the approved project sponsor, the ISO will require that any change in the personnel and contractors proposed to be used for the project must be approved by the ISO. Describe the legal and financial structure of the project sponsor and its team, including type of corporation if a corporation, or type of entity if it is a special purpose entity (e.g. project financed LLC) created explicitly for the proposed project. Describe the legal and financial relationship of the entity listed as the project sponsor to all other entities that are referred to in the application to include but not limited to all parent or holding company organizational entities, equity investors and any entity that will finance or otherwise financially support or provide guarantees for part or all of the project if different from the project sponsor. This description shall include the entity or entities that will own the assets of the project (whether through a special purpose entity or as part of a portfolio of assets or other mechanism) during the construction period and during the operating period.

Response:

A-6 State that the project sponsor is making a commitment to become a participating transmission owner for the purpose of turning the transmission element that the project sponsor is selected to construct and own as a result of the competitive solicitation process over to the ISO's operational control, to enter into the Transmission Control Agreement with respect to the transmission element, to adhere to all applicable reliability criteria, and to comply with NERC registration requirements and NERC and Western Electricity Coordinating Council (WECC) standards, where applicable.

Response:

2 PROJECT QUALIFICATION

Project Sponsor and Project Qualifications:

The ISO will review each project sponsor's proposal to assess the qualifications of the project sponsor and its project proposal based on the qualification criteria set forth in ISO Tariff section 24.5.3. The ISO will evaluate the information submitted by each project sponsor in response to the application items pertaining to sections 24.5.3.1(a)-(e) to determine whether the project sponsor has demonstrated that its team is physically, technically, and financially capable of (i) completing the needed transmission solution in a timely and competent manner and (ii) operating and maintaining the transmission solution in a manner that is consistent with good utility practice and applicable reliability criteria for the life of the project.

In addition, the ISO will determine whether the transmission solution proposed by a project sponsor is qualified for consideration, based on the qualification criteria contained in ISO Tariff sections 24.5.3.2(a) and (b). Please demonstrate that the proposed project meets the proposal qualification criteria for the needed transmission element by providing responses to the following two items (QP-1, QP-2) that relate to the qualification of the proposed project. When providing these responses, the project sponsor shall refer to information that has been provided in other sections of its application for additional information and support. The following two responses shall provide a complete demonstration or qualification – through the two responses directly and by including references in the two responses to material provided in responses to other items in the application.

Describe and demonstrate how:

QP-1. The proposed design of the transmission solution is consistent with needs identified in the comprehensive ISO transmission plan.

Response:

QP-2. The proposed design of the transmission solution satisfies applicable reliability criteria and ISO planning standards.

Response:

3 Prior Projects and Experience

In the accompanying Excel spreadsheet entitled Prior Projects and Experience Workbook, the project sponsor shall provide a description of all relevant prior projects and experience of the project sponsor on the Project Sponsor experience tab and its proposed contractors on the Contractor experience tab as it relates to this project. The lists of projects should include those with voltages greater than 200 kV completed in the past ten years. If the project sponsor or its proposed contractors do not have experience constructing facilities with voltages greater than 200 kV, but do have experience constructing lower voltage facilities, this experience may be included. Detailed explanations of schedule and budget variances may be supplied in a separate document if necessary as noted in the spreadsheet and shall include a description of major issues confronted and resolved during the project.

The Contractor experience tab of the Prior Projects and Experience Workbook shall be used to list the prior project experience of all contractors that the project sponsor proposes to use for this project, including but not limited to land acquisition, environmental permitting, design and engineering, construction, maintenance, and operations contractors. If the project sponsor proposes to but has not retained a contractor for any of the foregoing functions, the project sponsor shall provide a realistic short list of contractors under consideration. Any change to these contractors will require approval by the ISO. The evaluation will consider the qualifications of each submitted contractor. The experience list shall include any work performed by the contractor for the project sponsor. For environmental permitting contractors, the project sponsor must indicate in the spreadsheet, for each prior project listed for that contractor, the federal and state permits acquired as well as associated environmental processes, including federal NEPA or state environmental review determinations.

4 PROJECT MANAGEMENT AND SCHEDULE

P - 1. Provide a general description of the proposed approach to project management and scheduling for the transmission element.

Response:

P - 2. Provide the proposed management structure, organization, authority levels, and resources committed to project management and scheduling for the full scope of the project, including relevant experience and capability for the proposed project manager and other relevant decision-makers for the project. If the sponsor does not have a team in place, provide your plan to meet these requirements.

Response:

P - 3. Provide a proposed schedule for project development through release for operation that includes, at a minimum, key critical path items such as:
- Develop contracts for project work;
- Regulatory approval; permitting; rights of way and land acquisition;
- Engineering and design;
- Material and equipment procurement;
- Facility construction;
- Agreements (interconnection, operating, scheduling, etc.) with other entities;
- Pre-operations testing;
– Any amount of "float" incorporated into the schedule and how it was determined;
- Project in-service date;
- Other items identified by the project sponsor.

Provide a list of measures that the project sponsor would take to meet its schedule if the project sponsor encounters unanticipated delays in its schedule for land acquisition, permitting, or construction of up to 6 months. If the project sponsor proposes any financial or other incentives to ensure completion of the project on schedule, provide a description of those financial or other incentives.

Response:

P - 4. For the proposed project, identify the major risks and obstacles to successful project completion within cost budget while meeting schedule and identify proposed mitigations to minimize the risks. Describe all actions that the project sponsor will take to keep the project within budget while meeting schedule in light of the major risks identified.

If the project sponsor is sponsoring more than one project, the project sponsor shall also describe how the projected in-service date of this project (as reflected in the proposed schedule) would be affected if two or more of the project sponsor's proposals are selected.

Response:

P - 5. For the transmission line and substation projects included in the Prior Projects and Experience Workbook, provide the following:

(a) Any environmental permitting risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.

(b) Any transmission line or substation design or engineering risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.

(c) Any transmission line or substation construction risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.

(d) Any maintenance risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.

(e) Any operations risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.

(f) Other specific materials that reflect project management skills for an actual project.

Response:

5 Cost Assumptions and Containment

Provide all the information regarding cost containment for the proposed project in the Cost and Cost Containment Workbook. In addition, provide the information regarding the cost containment proposal in response to the following requests. Ensure the information provided in this application is consistent with the information provided in the Cost and Cost Containment Workbook.

CC-1 Fully describe in detail all of your proposed cost containment measures.

Response:

CC-2 Explain in detail and provide all bases, assumptions, reasons, support, and documentation as to why your estimated cost of debt constitutes a reasonable representation and expectation of the debt cost you expect to incur in connection with the project.

Response:

CC-3 Describe each proposed maintenance activity and its frequency planned over the life of the project facilities. Explain in detail and provide all bases, assumptions, reasons, and support as to why your estimated O&M costs (and Administrative and General (A&G) costs) constitutes a reasonable representation and expectation of the O&M costs you expect to incur in connection with the project. To the maximum extent practicable, provide this analysis for each individual component of total O&M costs as reflected in the Cost and Cost Containment Workbook.

Response:

CC-4 Identify by job category the number of full-time equivalent employees (FTE) the project sponsor intends to employ from its company to perform operations activities and the number of FTEs the project sponsor intends to employ from its company to perform maintenance activities. Also provide the number of FTEs that will be allocated to Administrative and General activities. Describe the specific role and functions each FTE will serve. Describe in detail the basis for and assumptions underlying these FTE estimates and the cost associated with the FTEs.

Response:

CC-5 Indicate whether the project sponsor intends to contract for O&M services.

a. If so, provide the name of the counterparty and attach any agreements that provide the terms of the relationship.
b. If the project sponsor intends to rely on O&M services from a regulated utility, identify the utility and describe in detail how the utility intends to support the project. Attach any agreements that provide the terms of the relationship.
c. Provide the specific roles and functions the contractors will provide for the project.

d. Provide in detail the justification for cost estimates associated with contracted O&M services.

e. For contracted O&M services, provide: (1) the number of FTEs- (on an annual basis) that would be conducting maintenance activities; (2) the number of FTEs- that would be providing operations services; and (3) the number of FTEs- that would be allocated to Administrative and General activities.

Response:

CC-6 Provide all details, assumptions, reasons, and supporting documentation (including manufacturers' guidelines) underlying the project sponsor's useful life projections for the project.

Response:

CC-7 Describe in detail all exclusions to any cost cap and cost containment measures the project sponsor proposes.

Response:

CC-8 If the project sponsor is proposing an exclusion for *force majeure* events, how exactly does the project sponsor propose to define *force majeure* for purposes of limiting exclusions from or increases to any cost cap and other cost containment measures?

Response:

CC-9 If a siting or permitting authority were to require relocation of the project sponsor's proposed site for the project, how exactly would that affect the project sponsor's proposed cost cap and other cost containment measures?

Response:

CC-10 If a siting or permitting authority were to require changes to the proposed structures, equipment, or transmission lines associated with the project sponsor's project, how would that affect the proposed cost cap and other cost containment measures?

Response:

CC-11 If a siting or permitting authority were to require an increase in the amount of environmental mitigation beyond that assumed in the project sponsor's proposal, how would that affect the proposed cost cap and other cost containment measures?

Response:

CC-12 If a siting or permitting authority were to require undergrounding of the project sponsor's proposed transmission facilities, or require overhead construction if the project sponsor has proposed undergrounding, how would that affect the proposed cost cap and other cost containment measures?

Response:

CC-13 If there were to be a delay in the receipt of any of the project sponsor's siting or permit authorizations, how exactly would that affect the proposed cost cap and other cost containment measures?

Response:

CC-14 If there were to be a delay in the schedule of the participating transmission owner for constructing its interconnection facility for the project, or if changes in project scope or location were to be required or caused by the interconnecting PTO, how would that affect the proposed cost cap and other cost containment measures?

Response:

CC-15 If one of the project sponsor's approved contractors was not able to meet its requirements, and the project sponsor were to propose and the ISO approve an alternate contractor, what impact would this have on the proposed cost cap and other cost containment measures?

Response:

CC-16 Indicate the authority of any agency with jurisdiction over the project to impose binding cost control measures or cost caps on the project, if the project sponsor is not proposing a cost cap.

Response:

6 FINANCIAL

The project sponsor (or the project sponsor's parent or other affiliated entity in the event the project sponsor must rely on either to meet this financial criteria) must demonstrate it has sufficient financial resources, including, but not limited to, satisfactory credit ratings and other financial indicators as well as the demonstrated ability to assume liability for major losses resulting from failure of any part of the facilities associated with the transmission solution. The ISO will consider the parent's or affiliated entity's financial statements, credit ratings, and other statements in this section if the parent or affiliated entity provides financial assurances acceptable to the ISO as described in F-2 below.

General

F - 1. Provide a list of equity holders, equity contribution by each investor, and the amount of debt over the entire life of the project.

Response:

F - 2. If the project sponsor is relying on a parent or another affiliated entity to satisfy the financial criterion of its application, (1) describe the entity's relationship to the project sponsor in the form of a corporate hierarchy and (2) provide a letter signed by an officer of the parent or affiliated entity indicating that the parent or affiliated entity provides financial assurances for the project. In addition, provide details of the parent's or affiliated entity's plan for providing for credit, investment, or financing arrangements for financial backing of the project. If financial recourse is limited, describe under what conditions recourse is available to the parent or affiliated entity's financial resources. Describe how these arrangements comply with all legal and regulatory requirements related to affiliate transactions.

Response:

Financial Strength and Creditworthiness

For the entity that has the financial resources to meet the financial strength and creditworthiness criteria and is required to provide financial assurances for the project, provide the information requested in F-3 through F-10.

F - 3. Provide annual, audited financial statements or equivalent (e.g., FERC Form 1) that at a minimum, includes an Auditors Statement, Management Statement, Balance Sheet, Income Statement, Statement of Cash Flows and Notes to the Financial Statements, for the most recent year and previous four years (five years total). If audited financial statements are not available, the project sponsor may provide other documentation demonstrating financial capability. In either case, the documentation **must be accompanied by a letter signed and attested to by an officer of the company** providing financial assurances that the documents are a fair representation of the financial condition of the company in accordance with generally accepted accounting practices. If this information is available electronically, it is acceptable for the project sponsor to provide links to the appropriate documents. NOTE: All financial statements must be provided in English.

Response:

F - 4. Provide quarterly, unaudited financial statements or equivalent (e.g. FERC Form 3-Q) published since the last annual, audited financial statement. If not available, the project sponsor may provide other documentation demonstrating financial capability. In either case, such documentation **must be accompanied by a letter signed and attested to by an officer of the company** providing financial assurances that the documents are a fair representation of the financial condition of the company in accordance with generally accepted accounting practices. If this information is available electronically, it is acceptable for the project sponsor to provide links to the appropriate documents. NOTE: All financial statements must be provided in English.

Response:

F - 5. If the creation of a special purpose entity (SPE) is being proposed for this project, describe the funding source(s) for the SPE for the duration of the project's useful life and how it fits into the corporate hierarchy. Explain how the capabilities and resources of the parent organization(s) of the SPE can be attributed to and will serve the SPE.

Response:

F - 6. Provide current credit ratings and rating agency reports from Moody's Investor Services, Standard & Poor's Ratings Services and/or Fitch Ratings, or another rating agency designated by the U.S. Securities and Exchange Commission as a Nationally Recognized Statistical Rating Organization. If credit ratings are unavailable, the project sponsor may provide other supporting information.

Response:

F - 7. Provide a report of any failure to make debt service payments on time during the previous five years. If the project sponsor is an SPE, report any such failures by its parent or other affiliated entities, including any predecessor SPEs.

Response:

F - 8. Provide a summary of any history of bankruptcy, dissolution, merger, or acquisition for the current calendar year and the five prior calendar years. If the project sponsor is an SPE, report any such events by its parent or other affiliated entities, including any predecessor SPEs.

Response:

F - 9. Based upon the most recent audited financial statements, provide a ratio of total assets to the total projected capital costs of the project, and show the calculation including any encumbrances.

Response:

F - 10. For each of the five years for which audited financial statements were provided according to F – 3 above, provide the following financial ratios, and show the calculation for each:

a. Funds from operations to interest coverage
b. Funds from operations to total debt
c. Total debt to total capital

Response:

Project Financing

F - 11. Describe the financing used on up to five projects listed in the Prior Projects and Experience Workbook that are similar in type and size to (or larger than) the transmission element and/or substation proposed in the application. Include the following in your response and use the table provided below:

1) Project description,
2) Financing structure (e.g., LLC vs. corporate),
3) Equity and debt contribution,
4) Debt sources,
5) Bank(s) involved,
6) Other important information.

F-11 (1)Project Description	(2)Financing Structure	(3)Equity and Debt Contribution	(4)Debt Sources	(5)Banks Involved	(6)Other Important Information

F - 12. Describe the proposed financing sources of funds and instruments for construction and working capital for this project by completing the following table:

Entity Providing Debt Financing	Loan Amount	Interest Rate	Repayment Period	Grace Period During Construction	Equity Provided by Project Sponsor

F - 13. For financing sources other than the capital markets, describe the benefits to ratepayers and others of your proposed financing source(s). This shall include the projected cost of the financing sources.

Response:

Project Liability Protection and Project Replacement and Repairs

F - 14. Provide the project sponsor's planned insurance coverage, including types of coverage and insured values during the construction period and over the operational life of the project facilities, including but not limited to covering negligent performance. Also include the types of losses to be covered during the construction and operation of the project, including specifying the extent of failure of project facilities to be covered by the planned insurance during the operation of the project.

Response:

F - 15. Describe your ability to finance unexpected repairs (*e.g.*, replacement of a series of towers) or replacement construction during the estimated useful life, *i.e.*, the operating period for the transmission element(s). For example, capabilities can include, but are not limited to, the following: use of account set-asides or accumulated funds, parent organization guarantees, letters of credit, letters of intent from financial institutions to support the project sponsor, insurance, or other means of ensuring that these increased costs can be covered in a timely manner and thus not delay the return of the project to normal operation.

Describe any actual events where the project sponsor had to cover increased costs due to equipment failures, including the nature of the event, costs incurred, and how these costs were funded by the project sponsor.

Response:

7 ENVIRONMENTAL PERMITTING AND PUBLIC PROCESSES

E - 1. Provide an overview of the various project activities that the project sponsor believes are needed to achieve siting approval, obtain all necessary permits, and any other necessary public processes required to construct the project. Provide a list of steps or flow chart for these project activities and processes. If the project is located within more than one state, provide a response for each state as applicable.

Response:

E - 2. Using your best estimate, indicate whether any federal discretionary permit(s) will be required. For each discretionary permit anticipated, identify the agency and applicable governing rule or statute. Describe these in detail, e.g., Clean Water Act Section 401- 404, U.S. Fish and Wildlife Service biological opinion.

Response:

E - 3. Using your best estimate, indicate whether any state discretionary permit(s) will be required and the type of permit to be filed (e.g., endangered species incidental take permit, water quality Section 401).

Response:

E - 4. Indicate if any federal land (for example, Forest Service, BLM) is proposed to be crossed, and if a NEPA (National Environmental Policy Act) environmental process is required.

Response:

E - 5. For projects within the State of California:

a. Indicate which agency is the expected California Environmental Quality Act (CEQA) lead agency. Explain why that agency was chosen and indicate whether that agency has agreed to be the lead agency for this project.

Response:

b. Provide a list of Best Management Practices[10] and project sponsor standing policies, related to siting and permit processes, that all employees are required to observe, including how are they implemented and how are they reported, that would be applicable for the proposed project.

[10] BMPs, which are environmental industry standard terminology, are the project sponsor's standards that would be common to all projects, i.e., not specific to any particular project. For example, this could consist of company training policies that relate to required safety training, environmental sensitivity training, accident and injury reporting, or community involvement programs involving both the local elected officials and the immediate community that will be impacted by the proposed project.

Response:

c. Provide a list of Applicant Proposed Measures that would be applicable for the proposed project. These are project sponsor mitigation measures that would be applied to reduce the potential environmental impact for a particular construction activity to ensure the impact is reduced below the level of a significant unavoidable impact. These are normally related to the CEQA checklist.

Response:

d. Indicate if you expect to perform any public outreach (e.g., open houses, project hotline number, project update mailings) and describe the planned outreach program.

Response:

E - 6. Provide information related only to transmission line, reactive support, series compensation, and substation siting and permits for projects developed by the project sponsor or its team in the past ten years. If the project sponsor is an SPE, provide information on the parent organization(s) for similar projects. Provide:

a. A description of any project siting or permitting notice of violation (NOV).

Response:

b. Siting or permitting fines levied by the project approval authority or any other agency with discretionary or ministerial authority over the project.

Response:

c. Remediation actions taken to avoid future violations.

Response:

d. A summary of siting or permitting law violations by the project sponsor or its team found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or in any other legal proceeding.

Response:

e. Any notice of violations that were remediated to the satisfaction of the issuing agency or authority.

Response:

f. A summary of any instances in which the project sponsor or its team is currently under investigation or is a defendant in any legal proceeding for violation of any siting or permitting law.

Response:

8 TRANSMISSION OR SUBSTATION LAND ACQUISITION

L - 1. Provide a general description of the land siting and acquisition needed for the proposed project and a map of the proposed project alignment and/or substation site on a suitable map base and scale - USGS quadrangle 1:24000 at a minimum. The map should show the study area for routing the project as well as any alternate routes, existing transmission lines, California Natural Diversity Data Base (CNDDB) information within the project area, and avoidance areas (such as parks, airports, military installations, and areas of local, state or national interest and any other major exclusion areas). Provide estimated acreages required. Include construction access, permanent access roads, laydown yards, and landing zones, if required. Show alternatives evaluated, those dismissed, and the justification for the preferred site.

Response:

L - 2. Provide a copy of the standard grant of easement anticipated and any temporary construction easement documents necessary for the project construction and a description of your proposed strategy for crop loss and or business loss compensation.

Response:

L - 3. Provide an indication of whether the project sponsor has eminent domain authority. If the project sponsor does not have eminent domain authority and does not plan to obtain eminent domain authority, describe the strategy for acquisition of necessary land rights.

Response:

L - 4. Indicate whether the project sponsor has any existing ROW or substations on which all or a portion of the transmission element can be built. For any such ROW describe how it would be used as part of the proposed project. Also, for any such ROW describe any incremental costs and risks associated with using the existing ROW (for example, negotiating additional land rights or the potential of "overburdening" existing easements). Does the project sponsor make a binding commitment to seek to use such existing ROW or substations for the project, and to use such existing ROW or substations unless the applicable siting authority or other regulatory agency determines otherwise, approves a different route, or the project sponsor is prevented from doing so by *force majeure* type events?

Response:

9 SUBSTATION DESIGN AND ENGINEERING

The items listed below should only be completed if the proposed transmission solution contains a substation or facilities similar to a substation (e.g., synchronous condenser, STATCOM).

S - 1. For each substation or reactive control element that is included as part of your proposed project, provide the location, GPS information, interconnection with new or existing transmission facilities, bus and breaker arrangement, typical structure types and materials that will be used, and any other unique aspects of the substation that the project sponsor proposes.

Response:

S –2. For each proposed substation, reactive support, or series compensation installation, provide the substation siting criteria that will be used on the project (e.g., future area plans, constructability, earthquake activity, flood plain and mudslide considerations).

Response:

S – 3. For each proposed substation, reactive support, or series compensation installation, provide the basic parameters for the installation - primary and secondary voltage, BIL[11], initial design power capacity, and final design power capacity (if developed in stages).

Response:

S – 4. For each proposed substation, reactive support, or series compensation installation, provide a preliminary design criteria document that specifies the criteria that will be used in the design of the facility. Also provide a list of standards and requirements that will be used in its design - e.g., IEEE 142. Provide a complete list of state specific requirements for each U.S. state in which the project will be located (e.g., California and other state specific requirements if part of the project or the entire project is located outside California).

Response:

S – 5. For each proposed substation, reactive support, or series compensation installation, provide a single line diagram and general arrangement plan, which includes:

i. bus and breaker arrangement,
ii. transformer arrangement,
iii. automatic tap changer, if any,
iv. power factor correction equipment if any,
v. voltage regulator, if any,
vi. ground fault limiting resistor or reactor, if any,
vii. line terminations for existing or proposed transmission lines,
viii. bus type and rating,

[11] A design voltage level for electrical apparatus that refers to a short duration (1.2 x 50 microsecond) crest voltage and is used to measure the ability of an insulation system to withstand high surge voltage.

ix. high voltage switch types and ratings,
x. switchgear type and ratings,
xi. battery system arrangements,
xii. substation, reactive support, or series compensation facility layout with equipment location, fencing, grounding, control/relay building, etc.

Response:

S – 6. For each proposed substation, reactive support, or series compensation installation, describe the protection system criteria and specific components included in the design for primary and back-up protection. Identify any special protection considerations for the substation.

Response:

S – 7. For each proposed substation, reactive support, or series compensation installation, describe the SCADA incorporated in the design. Include the project sponsor's commitment to meet operational data requirements and a specific description of the communications strategy.

*Res*ponse:

S – 8. For each proposed substation, reactive support, or series compensation installation, describe the physical security criteria and specific security measures that will be incorporated in the final facility design.

Response:

10 Transmission Line Design and Engineering

The items listed below should only be completed if there is a transmission line included in the proposed transmission solution.

T - 1. Provide a general overview and description of the transmission line that the project sponsor proposes, including the following items. Use the table provided below for your responses:

a. The starting and ending points including length of preferred route. If the route is in more than one state, provide the information for each state. This shall include GPS coordinates.
b. proposed conductor size, bundling and type,
c. intervening substations, switching stations, or series compensation facilities,
d. typical span lengths,
e. any other unique aspects of the line that the project sponsor proposes that has not previously been provided for the overhead portions of the line.

If any underground transmission is proposed, include a general description of the following items:

f. the underground conductor size and type and length of segment(s),
g. the proposed termination facilities, and
h. any other unique aspects of the underground portion of the line not previously provided.

T-1 Item	Response
a	
b	
c	
d	
e	
f	
g	
h	

T - 2. Provide the transmission line siting criteria that will be used for any overhead section of the proposed transmission line and any underground sections of the proposed transmission line.

Response:

T - 3. Provide a listing of all existing or permitted transmission lines, including voltage, structure type, and separation, located adjacent to or in the same corridor as the proposed project. Provide the criteria used to establish the separation between the proposed transmission line and existing transmission and distribution facilities.

Response:

T - 4. Provide the preliminary design criteria document for any overhead section of the proposed transmission line and any underground section of the proposed transmission line.

Response:

T - 5. Provide a list of standards and requirements that will be used in the transmission line design for both overhead and underground, e.g., IEEE 951, ASCE Manual No. 72, GO 95, with an emphasis on providing a complete list of state specific requirements and the requirements of other states where the proposed project will be located. Also provide any interconnection standards for interconnection of the project to existing utility system(s).

Response:

T - 6. Provide a single line diagram and a general arrangement plan of the entire proposed transmission line, including transmission line crossings by the new project line. For crossings, provide a list by voltage and type of construction of lines crossed (either over or under) by the proposed project. Include isolation devices to be installed for operations and maintenance purposes.

Response:

T - 7. For any proposed overhead transmission line, provide the following additional information not included in response to T-1 in the table provided below:

a. Basic parameters of the transmission line(s) - Design voltage, BIL (design or adjacent substation criteria), initial design power capacity and final design power capacity (if developed in stages).

Support Structures

For any support structures including wood poles, tubular poles, and lattice steel structures, provide:

b. a description of the proposed support structures and conductor geometry,
c. structure foundations as appropriate and grounding criteria and implementation,
d. insulation level, insulator types,
e. lightning protection,
f. estimated right of way widths for each different segment of the project with drawings for each and the basis of determining each right of way width.

Line Ratings and Impedance

g. Provide the estimated per mile line impedances for each different line section proposed in the project, suitable for use in power flow, system stability, and system protection studies. Also provide an estimate of the completed line overall impedance in per unit on a 100 MVA base.
h. Provide NESC and/or GO 95 Grade of Construction.

i. Provide NESC and/or GO 95 Loading Corridor Separation.

T-7 Item	Response
a	
b	
c	
d	
e	
f	
g	
h	
i	

T - 8. For any proposed overhead section and any underground section of the transmission line, provide the ampacity rating methodology including maximum conductor temperature that will be used to determine the normal and emergency ratings of the overhead line for summer and winter. Provide the actual ampacity for the line under normal conditions and emergency operations (specify time limit for emergency operations) for summer and winter operating conditions.

Response:

T - 9. For any proposed underground transmission sections, provide the following additional information not included in response to T-1 in the table provided below:

a. Type of transmission cable, including splicing and cable grounding,
b. Substructures, conduits and duct banks, and splicing enclosures,
c. Termination facilities and structures,
d. Description of the type of transmission cable, including splicing and cable grounding,
e. Provide the estimated per mile line impedances for each different line section proposed in the project. All line impedances shall be provided on a per unit 100 MVA base. Also provide an estimate of the completed line overall impedance.
f. lightning protection,
g. estimated right of way widths for each different segment of the project with drawings for each and the basis of determining each right of way width.

T-9 Item	Response

a	
b	
c	
d	
e	
f	
g	

T - 10. For each substation that the proposed transmission line would terminate in that will not be the responsibility of the project sponsor to modify in order to interconnect the line, provide the following information in the table below:

a. Name of the substation where the interconnection will take place.
b. A description of the demarcation point that identifies the point in the interconnection where responsibility for implementation (e.g., design, construction, testing) changes from the project sponsor to the substation owner.
c. List of agreements that must be reached with the substation owner or others to interconnect and operate the proposed line to the substation (e.g., interconnection agreement, schedule agreement).
d. A description of the project sponsor's approach to determining if any environmental permitting will be required to terminate the proposed line at the substation
e. A description of the approach the project sponsor's will use to determine the cost to implement changes at the substation or other locations that are associated with the interconnection of the proposed project at the substation and of those costs which will paid for by the project sponsor.

T-10 Item	Response
a	
b	
c	
d	
e	

11 CONSTRUCTION

Provide an overview and description of the construction plan and management practices that the project sponsor proposes to follow in response to the questions below:

C-1 Description of inspection of construction activities, including substations, reactive support, series compensation installations, overhead transmission lines, and underground transmission lines if part of the project.

Response:

C-2 Description of the method of establishing material yards, sequencing and receiving material, providing material to contractors, material quality control methods, and material expediting processes.

Response:

C-3 Description of the method of coordination of the duration and timing of any clearances of existing circuits necessary during construction.

Response:

C-4 Description of the plans for a constructability review including completeness of engineering drawings, construction specifications, material orders, and tracking and providing changes.

Response:

C-5 Description of the status of easements orders of possession, permits, and compliance with pre- construction permit conditions and mitigation measures.

Response:

C-6 Description of the method for detail scheduling showing sequence of work, environmental restrictions, clearances requirements, progress reports, and actions taken to maintain schedule.

Response:

C-7 Description of any unique or special construction techniques proposed for any aspect of the proposed project, including ROW clearing, construction and permanent access road construction, and expected helicopter work.

Response:

C-8 Provide information related only to transmission line, reactive support, series compensation, and substation construction for projects developed by the project sponsor or its team for projects completed during the past ten years. If the project sponsor is an SPE, provide the information for the parent organization(s). Provide

a. A description of any project construction-related notice of violation (NOV).

Response:

b. Construction-related fines levied by the project approval authority or any other agency with discretionary or ministerial authority over the project.

Response:

c. Remediation actions taken to avoid future violations.

Response:

d. A summary of construction-related law violations by the project sponsor or its team found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or in any other legal proceeding.

Response:

e. Any notice of violations that were remediated to the satisfaction of the issuing agency or authority.

Response:

f. A summary of any instances in which the project sponsor or its team is currently under investigation or is a defendant in any legal proceeding for violation of any construction-related law.

Response:

12 Maintenance

M-1 Describe the roles and responsibilities of the project sponsor's maintenance organizations. Describe any organizational changes to the project sponsor's current organization that are planned to accommodate maintenance of the proposed project. Provide any contract you have with a third party to provide maintenance services for the project. Describe what specific maintenance activities will be handled by project sponsor staff and which activities will be handled by contractors or vendors.

Response:

M-2 Describe the project sponsor's policies, processes, and procedures for assuring that only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations are employed. Include qualifications, certifications, and experience requirements for maintenance and field personnel.

Response:

M-3 Describe the project sponsor's training program for maintenance personnel. Include initial and continuing education requirements for maintaining qualifications for classifications with maintenance responsibilities (e.g., what are the training and certification requirements for linemen and substation electricians?). Identify training resources used.

Response:

M-4 Describe the project sponsor's capabilities that will enable it to comply with the maintenance standards described in Appendix C of the TCA. Indicate whether or not the project sponsor's standards include the elements listed in TCA Appendix C Sections 5.2.1 (Transmission Line Circuit Maintenance) and 5.2.2 (Station Maintenance). (Note: Each PTO will prepare its own maintenance practices that shall be consistent with the requirements of the ISO Transmission Maintenance Standards. The effectiveness of each PTO's maintenance practices will be gauged through the ISO's availability performance monitoring system. Each PTO's adherence to its maintenance practices will be assessed through an ISO review pursuant to TCA Appendix C Maintenance Procedure 4).

Response:

M-5 Describe the project sponsor's vegetation management plan as it applies to the proposed project. Provide the project sponsor's preexisting procedures and historical practices for managing ROW for transmission facilities.

Response:

M-6 Provide information, notices, or reports regarding the project sponsor's compliance with its standards for inspection, maintenance, repair, and replacement of similar facilities. Include audit reports or regulatory filings.

Response:

M-7 Describe the project sponsor's capabilities that will enable it to provide its Availability Measures in accordance with TCA Appendix C Section 4.3 as applicable. Provide sample availability measures, or similar measures, for other facilities owned by the project sponsor to demonstrate the project sponsor's capability.

Response:

M-8 Would adding the project to the ISO controlled grid require any changes or exceptions to the provisions of the TCA? If "yes", describe.

Response:

M-9 Describe the project sponsor's (its team or planned team) capabilities that will enable it to comply with the activities required by TCA Section 7 (Operations and Maintenance [including Scheduled Maintenance, Exercise of Contractual Rights, and Unscheduled Maintenance]).

Response:

M-10 Specify where the project's maintenance team (including any project sponsor staff and contractors) will be located. Specify the estimated response time of any assigned project sponsor staff, maintenance contractor, or emergency response provider.

Response:

13 OPERATIONS

O-1 Describe the roles and responsibilities of the operations organizations, including operating jurisdictions as they relate to the proposed project. Identify the planned location of those responsible for operation of the project, including the location of the control center that will serve as the single point of contact for the ISO. Describe any organizational changes to the project sponsor's current operations organization that are planned to accommodate the proposed project. Provide any contract you have with a third party to provide operation services for the project. Describe what specific operations activities will be handled by project sponsor staff and what activities will be handled by contractors or vendors.

Response:

O-2 Describe the project sponsor's policies, processes, and procedures for assuring that only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations are employed. Include qualifications, certifications, and experience requirements for operators and field personnel.

Response:

O-3 Describe the project sponsor's training program for operations personnel. Include initial and continuing education requirements for maintaining qualifications for classifications with operation responsibilities (e.g., what are the training and certification requirements for operators, linemen, and substation electricians?). Identify training resources used.

Response:

O-4 Would adding the project to the ISO controlled grid require any changes or exceptions to the provisions of the TCA regarding operations? If "yes", describe.

Response:

O-5 Identify the NERC functions for which the project sponsor has registered or intends to become registered related to the proposed project.

Response:

O-6 If the project sponsor plans to contract for services to perform the NERC functions, identify the contractor and the NERC functions for which it is registered or intends to become registered. If you plan to use a contractor and have not selected one yet, provide the requested information for the contractors you are considering. Describe how the project sponsor will ensure compliance with the reliability standards or requirements associated with these functions. Provide any contract you have with a third-party to perform NERC functions.

Response:

O-7 Describe the approach the project sponsor will use to assure compliance with Applicable Reliability Standards. Include descriptions of organizational responsibility, processes, and procedures for assuring compliance. Identify any Applicable Reliability Criteria for which transmission owners are responsible that require temporary waivers under TCA Section 5.1.6. Explain any.

Response:

O-8 Provide information demonstrating that the project sponsor, or its intended contractor or contractors as identified in O-1, has been in compliance with the Applicable Reliability Standards for all transmission facilities that it owns, operates, or maintains. This could include information for facilities outside the ISO controlled grid and shall include available NERC compliance audit results. Provide information describing the amount of transmission facilities subject to NERC compliance by listing the number of miles of transmission lines by voltage class and the number of substations by voltage class. If the project sponsor does not have experience with transmission facilities subject to NERC reliability standards, provide information demonstrating compliance with standards that do apply to those facilities and the amount of facilities subject to such compliance.

Response:

O-9 Describe in general how the project sponsor proposes to divide responsibility for NERC reliability standards between the project sponsor and the ISO in the Coordinated Functional Registration agreement. Compare your response with existing agreements between the ISO and other PTOs, and describe expected differences, if any. Existing agreements are available on the ISO website.

Response:

O-10 Describe the applicable agreements that will define the responsibilities of the Transmission Operator as defined in NERC reliability standards and authority with respect to NERC reliability standards categories of Generator Owner(s), Generator Operator(s), Planning Authority(ies), Distribution Provider(s), Transmission Owner(s), Transmission Service Provider(s), Balancing Authority(ies), Transmission Planner(s), and adjacent Transmission Operator(s).

Response:

O-11 Describe how the project sponsor will meet the NERC reliability standards requirement that a Transmission Operator have adequate and reliable data acquisition facilities for its Transmission Operator Area and with others for operating information necessary to maintain reliability. Include back-up control center plans if any. Also include provisions for providing the availability data required by TCA Appendix C Section 4.3.

Response:

O-12 Describe the project sponsor's (its team or planned team) capability that will enable it to comply with the activities required by TCA Section 6.1 (Physical Operation of Facilities [including Operation, ISO Operating Orders, Duty of Care, Outages, Return to Service, and Written Report]) and TCA Section 6.3 (Other Responsibilities).

Response:

O-13 Describe the project sponsor's capability (for its team or its planned team) that will enable it to comply with the activities required by TCA Section 9.2 (Management of Emergencies by Participating TOs) and TCA Section 9.3 (System Emergency Reports: TO Obligations). Identify resources available to respond to major problems on the proposed project. Include resources available through mutual assistance agreements and describe expected response times. Provide samples of emergency operating plans.

Response:

O-14 Will the project be subject to any encumbrance? If so, provide a statement of any Encumbrances to which any of the transmission lines and associated facilities to be placed under ISO Operational Control are subject, together with any documents creating such Encumbrances and any instructions on how to implement Encumbrances and Entitlements in accordance with TCA Section 6.4.2.

Response:

O-15 Identify the plans or provisions to be implemented by the project sponsor to replace major failed equipment, e.g., a substation transformer, circuit breaker, or a group of towers (including dead end structures).

Response:

O-16 Identify and describe any violations of NERC reliability standards or other reliability standards the project sponsor or its team has incurred in the past ten years.

Response:

O-17 Identify and describe any operations-related tariff violations or FERC rules violations the project sponsor or its team has incurred in the past ten years.

Response:

O-18 Identify and describe any violations of operations-related laws, statutes, rules, or regulations the project sponsor or its team has incurred in the past ten years that are not discussed elsewhere in the application.

Response:

14 MISCELLANEOUS:

Z-1: Provide any additional evidence or support that the project sponsor believes supports its selection as an approved project sponsor. This can include, but is not limited to, other benefits the project sponsor's proposal provides, specific advantages that the project sponsor or its team have, or any efficiencies to be gained by selecting the project sponsor's proposal or additional information that was not requested in the other sections that supports the selection of the sponsor's proposal. Do not include information that is already included in other sections of the application.

Response:

15 OFFICER CERTIFICATION

OFFICER CERTIFICATION FORM

Project Sponsor Name:

I, ____, an officer of the entity identified above as the Project Sponsor or affiliate of the Project Sponsor, understanding that the ISO is relying on the information set forth in the foregoing application, including associated worksheets, to select an Approved Project Sponsor for the transmission element that is the subject of the application, hereby certify that I have full authority to represent the Project Sponsor or affiliate of the Project Sponsor, as described below. I further certify that:

1. I am the _________________________(title) of _______________________ (Project Sponsor).

2. I have prepared, or have reviewed, all of the information contained in the foregoing application, including associated worksheets, which is being submitted into the ISO's competitive selection process for the:

   ____(name of transmission element).

3. On behalf of the Project Sponsor, I agree that any dispute between the ISO and the Project Sponsor regarding any aspect of the competitive selection process, including the ISO's selection report, will be resolved in accordance with ISO Tariff Section 13 ("Dispute Resolution").

I acknowledge that I understand the relevant provisions of Section 24.5 of the ISO Tariff and the Business Practice Manual for Transmission Planning applicable to the Project Sponsor's application, including, but not limited to, those provisions describing the information that will be used by the ISO to determine the Project Sponsor's qualifications to participate in the competitive selection process and the criteria that the ISO will apply in the comparative evaluation for purposes of Selecting an Approved Project Sponsor. I certify, after due investigation, that the information provided in the application, including associated worksheets, is true and accurate to the best of my belief and knowledge and there are no material omissions. In addition, by signing this certification, I acknowledge the potential consequences of making incomplete or false statements in this certification, which may include exclusion from the current and subsequent competitive selection processes.

____
(Signature)

Print Name: ______________________________

Title: ______________________________

Date: ______________________________

16 APPLICATION DEPOSIT PAYMENT INSTRUCTIONS

Please complete this entire form.

Project Sponsor Deposit Information

1. **Name of Phase 3 Project: _____**

2. **Name, address, telephone number, and e-mail address of the Customer's contact person (primary person who will be contacted):**

   Name: _____
   Title: _____
   Company Name: _____
   Street Address: _____
   City, State: _____
   Zip Code: _____
   Phone Number: _____
   Fax Number: _____
   Email Address: _____

3. **Alternate contact:**

   Name: _____
   Title: _____
   Company Name: _____
   Street Address: _____
   City, State: _____
   Zip Code: _____
   Phone Number: _____
   Fax Number: _____
   Email Address: _____

4. **Any deposit paid by check shall be submitted to the CAISO representative indicated below: Note – the check may be included with applications submitted on CDs or DVDs. Checks shall be made payable to the CAISO.**

	Overnight Address
California ISO	California ISO
Attn: Julie Balch	Attn: Julie Balch
Grid Assets	Grid Assets
P.O. Box 639014	250 Outcropping Way
Folsom, CA 95763-9014	Folsom, CA 95630

5. Project Sponsor Deposit is submitted by:

Legal name of the Customer: _____
By (signature): ____
Name (type or print): _____
Title: _____
Date: _____

**Required Deposit: $75,000 USD (note: Wires originating from outside the U.S. are subject to currency conversion rates and/or additional bank fees).
**Your application will not be considered received if the deposit is not received prior to the bid window close date.

Wire Information

California ISO - Remit to Addresses
Beneficiary Bank Name
Beneficiary Bank Address
Wells Fargo Bank, NA
420 Montgomery St.
San Francisco, CA 94104

LGIP/SGIP
Wells Fargo Bank, NA
ABA # 121000248
Account # 4122041825
Account name: CAISO LGIP

California ISO

Approval History

Approval Date: June 23, 2023

Effective Date: June 23, 2023

Application Owner: Scott Vaughan

Application Owner's Title: Manager, Transmission Assets

Revision History

Version	Date	Description
8	6/23/2023	Added clarification for including experience, added reference to GPS coordinate idenitification of subs and transmission lines, eliminated original question L1 , added request for more detail on schedule float in P3
7	3/22/2021	Revised Version Released - General update and simplification
6	4/17/2019	General update
5	5/10/2016	General update and revised to address stakeholder comments.
4	4/7/2014	Revised to align with updated tariff.
3	4/4/2013	Revised Version Released – Add Version Control, Approval History, and Revision History Sections
2	4/1/2013	Revised Version Released - General clarification modifications and clean-up for 2012-2013 TPP Phase 3 Bid Window Opening
1	12/19/2012	Initial Version Released

EXHIBIT 4

CAISO-HORIZON WEST APPROVED PROJECT SPONSOR AGREEMENT FOR THE IRONWOOD PROJECT (DECEMBER 24, 2024)

(PUBLIC VERSION)

APPROVED PROJECT SPONSOR AGREEMENT (APSA)

BETWEEN

HORIZON WEST TRANSMISSION, LLC

AND

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

NORTH GILA – IMPERIAL VALLEY #2 KV LINE PROJECT

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APPENDICES

APPROVED PROJECT SPONSOR AGREEMENT

HORIZON WEST TRANSMISSION, LLC

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

THIS APPROVED PROJECT SPONSOR AGREEMENT ("Agreement") is made and entered into this 29th day of December, 2024, between Horizon West Transmission, LLC, organized and existing under the laws of the State of Delaware ("Approved Project Sponsor"), and the California Independent System Operator Corporation, a California nonprofit public benefit corporation organized and existing under the laws of the State of California ("CAISO"). Approved Project Sponsor and the CAISO each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, the CAISO exercises Operational Control over the CAISO Controlled Grid; and

WHEREAS, the Approved Project Sponsor is an indirect subsidiary of NextEra Energy, Inc. ("NextEra") and an affiliate of NextEra Energy Capital Holdings, Inc. ("NEECH"), a wholly-owned subsidiary of NextEra that owns and provides funding for NextEra's operating subsidiaries, including the Approved Project Sponsor.

WHEREAS, the Approved Project Sponsor intends to construct, finance, and own the North Gila – Imperial Valley #2 500 kV Line Project ("Project") consisting of transmission facilities identified in Appendix A to this Agreement; and

WHEREAS, if applicable, the Approved Project Sponsor will seek interconnection of the Project from the Interconnecting PTO or other entity in accordance with the requirements provided in this Agreement; and

WHEREAS, the Parties agree that the Approved Project Sponsor will enter into the Transmission Control Agreement to become a Participating Transmission Owner ("Participating TO"), if it is not already a Participating TO, effective upon energization of the Project, and will turn the Project over to the Operational Control of the CAISO; and

WHEREAS, the Parties recognize that the Approved Project Sponsor has certain rights and obligations related to the Project that arise prior to the date upon which the Approved Project Sponsor will place the facilities under the CAISO's Operational Control and, if not already a Participating TO, will become a Participating TO and which may remain in effect for a discrete period of time after the Approved Project Sponsor enters into the Transmission Control Agreement; and

WHEREAS, the Approved Project Sponsor and the CAISO thus have agreed to enter into this Agreement for the purpose of identifying rights and obligations associated with the Project that arise prior to the effective date of the Approved Project Sponsor's execution of the Transmission Control Agreement;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

ARTICLE 1. DEFINITIONS

When used in this Agreement, a term with initial capitalization shall have the meaning set forth in this Article 1 or the recitals, or if not defined in this Article 1 or the recitals, shall have the meaning specified in the Article in which it is used or in the CAISO Tariff, Appendix A.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state, and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits, and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the Western Electricity Coordinating Council or its successor.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Balancing Authority Area of the Interconnecting PTO's Transmission System to which the Project is directly connected, including requirements adopted pursuant to Section 215 of the Federal Power Act.

Breach shall mean the failure of a Party to perform or observe any material term or condition of this Agreement.

Breaching Party shall mean a Party that is in Breach of this Agreement.

Confidential Information shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, subject to Article 19.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 14 of this Agreement.

Effective Date shall mean the date on which this Agreement becomes effective as specified in Article 2.

Environmental Law shall mean Applicable Laws and Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, or explosion, any order, regulation, or restriction imposed by governmental, military, or lawfully established civilian authorities, or any other cause beyond the reasonable control of the Parties that could not have been avoided through the exercise of Good Utility Practice. A Force Majeure event does not include (1) acts of negligence or intentional wrongdoing by the Party claiming Force Majeure; (2) economic conditions that render a Party's performance of this Agreement unprofitable or otherwise uneconomic; (3) economic hardship of either Party; or (4) failure or delay in granting of necessary permits for reasons not caused by Force Majeure.

Governmental Authority shall mean any federal, state, local, or other governmental, regulatory, or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Approved Project Sponsor, the CAISO, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials, or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants," or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material, or substance, exposure to which is prohibited, limited, or regulated by any applicable Environmental Law.

Interconnecting PTO shall mean any Participating TO, other than the Approved Project Sponsor that owns or is building transmission facilities to which the Project will interconnect.

Interconnection Handbook shall mean a handbook, developed by the Interconnecting PTO and posted on the Interconnecting PTO's web site or otherwise made available by the Interconnecting PTO, describing technical and operational requirements for controls and protection equipment for transmission connected to the Interconnecting PTO's portion of the CAISO Controlled Grid, as such handbook may be modified or superseded from time to time. Interconnecting PTO's standards contained in the Interconnection Handbook shall be deemed consistent with Good Utility Practice.

Loss shall mean any and all damages, losses, and claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties.

Metering Equipment shall mean all metering equipment installed or to be installed for measuring the Balancing Authority Area boundary pursuant to this Agreement at the metering points, including instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Party or Parties shall mean the CAISO, the Approved Project Sponsor, or the applicable combination of the above.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under this Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

System Protection Facilities shall mean equipment, including necessary protection signal communications equipment, that protect (1) the Interconnecting PTO's Transmission System, Interconnecting PTO's Transmission Interconnection Facilities, CAISO Controlled Grid, and Affected Systems from faults or other electrical disturbances and (2) the Approved Project Sponsor's Transmission System from faults or other electrical system disturbances occurring on the CAISO Controlled Grid, Interconnecting PTO's Transmission Interconnection Facilities, and Affected Systems or on other delivery systems or other generating systems to which the CAISO Controlled Grid is directly connected.

Transmission Interconnection Facilities shall mean the Interconnecting PTO's or other entity's transmission facilities, including any modification, additions, or upgrades, that are necessary to physically and electrically interconnect the Project to the Interconnecting PTO's Transmission System.

Transmission Interconnection Service shall mean the service defined in Section 4.2 of this Agreement.

ARTICLE 2. EFFECTIVE DATE, TERM, AND TERMINATION

2.1 Effective Date. This Agreement shall become effective upon execution by all Parties, subject to acceptance by FERC (if applicable). The CAISO shall promptly file this Agreement with FERC upon execution in accordance with Section 3.1, if required.

2.2 Term of Agreement. This Agreement shall remain in effect until termination consistent with Section 2.3.

2.3 Agreement Termination.

2.3.1 Except for the obligations set forth in Sections 5.6, 5.10, 10.1.1, 10.3, Article 15 and Appendix E, this Agreement shall terminate when the Project has been turned over to CAISO Operational Control.

2.3.2 A Party may terminate this Agreement in accordance with Section 5.8 or Article 14.

2.3.3 Notwithstanding Sections 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination and, if applicable, FERC has accepted the notice of termination.

ARTICLE 3. REGULATORY FILINGS AND CAISO TARIFF COMPLIANCE

3.1 Filing. The CAISO shall file this Agreement (and any amendment hereto) with the appropriate Governmental Authority, if required. The Approved Project Sponsor may request that any information included in such filing be subject to the confidentiality provisions of Article 19. If the Approved Project Sponsor has executed this Agreement, or any amendment to this Agreement, the Approved Project Sponsor shall reasonably cooperate with the CAISO with respect to such filing and to provide any information reasonably requested by the CAISO needed to comply with applicable regulatory requirements.

3.2 Agreement Subject to CAISO Tariff. The Approved Project Sponsor shall comply with all applicable provisions of the CAISO Tariff.

3.3 Relationship Between this Agreement and the CAISO Tariff. If and to the extent a provision of this Agreement is inconsistent with the CAISO Tariff and dictates rights and obligations between the CAISO and the Approved Project Sponsor, the CAISO Tariff shall govern.

3.4. Requirement to Become a Participating TO. The Approved Project Sponsor agrees that the Project shall be placed under CAISO Operational Control upon completion of the Project. To the extent the Approved Project Sponsor is not already a Participating TO, the Approved Project Sponsor further agrees that it shall enter into the Transmission Control Agreement in sufficient time for its execution to become effective as of the date of energization of the Project and that it has met or shall meet all other CAISO Tariff requirements to become a Participating TO in accordance with Section 4.3 of the CAISO Tariff.

3.5 Relationship Between this Agreement and the Transmission Control Agreement. Once the Approved Project Sponsor has entered into the Transmission Control Agreement, if and to the extent a matter specifically addressed in this Agreement is inconsistent with the Transmission Control Agreement, the terms of the Transmission Control Agreement shall govern.

ARTICLE 4. SCOPE OF SERVICE

4.1 Transmission Facilities. The Approved Project Sponsor shall build and connect to the CAISO Controlled Grid the Project identified in Appendix A.

4.2 Transmission Interconnection Service. Transmission Interconnection Service allows the Approved Project Sponsor to connect the Project to the facilities of an Interconnecting PTO or a transmission system that is not part of the CAISO Controlled Grid. Unless the Project connects solely to the facilities of the Approved Project Sponsor, the Approved Project Sponsor shall request Transmission Interconnection Service from the Interconnecting PTO or other entity according to the milestones set forth in Appendix B and shall comply with the Interconnecting PTO's or other entity's applicable transmission interconnection procedures. The Approved Project Sponsor must obtain a separate agreement for Transmission Interconnection Service from the Interconnecting PTO or any other entity to whose facilities the Project will interconnect. This separate agreement with each Interconnecting PTO or other entity must provide, at a minimum, for the Interconnecting PTO or other entity to take any procedural steps required in this Agreement with respect to the transmission interconnection, including Sections 5.3.4, 5.4.2, 5.4.3, 5.5.3, 5.6.2, 6.1, 8.1, and 9.2, and must identify the Transmission Interconnection Facilities that an Interconnecting PTO is responsible for, and must pay for in accordance with Section 24.14.2 of the CAISO Tariff. The CAISO may facilitate the coordination between the Approved Project Sponsor and the Interconnecting PTO contemplated by this Agreement.

4.2.1 The Transmission Interconnection Service agreement shall require that the Interconnecting PTO or other entity providing Transmission Interconnection Service provide to the CAISO, every ninety (90) calendar days until the Project is energized and under CAISO Operational Control, a Transmission Interconnection Facilities status report. Such status report shall include project schedule; permit and license status, including environmental, state, and local permits and licenses; right-of-way acquisition status, if required; land acquisition status, if required; design and engineering status; status of contracts for project work, including land, procurement, and staffing; construction status; testing status; events creating risks and obstacles to project completion; and project budget, including actuals, estimate to complete, and contingency. The format for the report shall be in accordance with the Business Practice Manual for the Transmission Planning Process.

4.3 Approved Project Sponsor to Meet Requirements of the Interconnecting PTO's Interconnection Handbook. If applicable, the Approved Project Sponsor shall comply with the Interconnecting PTO's Interconnection Handbook for the transmission interconnections.

4.4 Performance Standards. Each Party shall perform all of its obligations under this Agreement in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice. To the extent a Party is required to take or prevented from or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this Agreement for its lack of compliance therewith, and if such Party is the CAISO, then the CAISO shall have the authority to amend this Agreement unilaterally to eliminate the conflict with such regulations or standards and shall submit the amendment to FERC for approval, if applicable.

ARTICLE 5. FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.1 General. The Approved Project Sponsor shall, at its expense, design, procure, construct, own, and install the Project, as set forth in Appendix A. The Approved Project Sponsor shall comply with all requirements of law and shall assume responsibility for the design, procurement, and construction of the Project using Good Utility Practice and the standards and specifications provided by the Interconnecting PTO or other entity, if applicable. The Project shall be based on the assumed accuracy and completeness of all technical information received by the CAISO from the Approved Project Sponsor and by the Approved Project Sponsor from any Interconnecting PTO or other entity providing Transmission Interconnection Service. Changes to the Project design described in this Agreement must be approved by the CAISO in accordance with Section 5.9 of this Agreement. Unless otherwise agreed by the Parties, the Approved Project Sponsor shall select the testing date and the energization date for the Project consistent with the Approved Project Sponsor's application approved by the CAISO, and such dates shall be set forth in Appendix B (Milestones).

5.2 Information Exchange. As soon as reasonably practicable after the Effective Date, the Approved Project Sponsor shall provide information to the CAISO regarding the design and compatibility of the Project and the Transmission Interconnection Facilities, and shall work diligently and in good faith to make any necessary design changes to the Project, subject to approval by the CAISO in accordance with Section 5.9. The Parties shall amend the description of the Project set forth in Appendix A to reflect any agreed changes to the Project.

5.3 Initial Construction Plan and Reporting Requirements. The Approved Project Sponsor shall keep the CAISO advised monthly as to the progress of the financing, procurement, and construction efforts with respect to the Project, via email or verbal discussion as agreed upon by the Parties, and in accordance with the timeframes specified herein.

5.3.1 The Approved Project Sponsor shall provide the CAISO with the initial construction plan one hundred twenty (120) calendar days after the Approved Project Sponsor has been selected in accordance with Section 24.4.1 of the CAISO Tariff. The plan shall include: land acquisition and permits requirements, status, and schedule; materials procurement requirements, status, and schedule; construction financing status and schedule; and Project contact information, if different than as identified in the selection process.

5.3.2 Every ninety (90) calendar days after the initial construction plan is received until the Project is energized and under CAISO Operational Control, the Approved Project Sponsor shall provide the CAISO with a construction plan status report. Such status report shall include the Project schedule; permit and license status, including environmental, state, and local permits and licenses; right-of-way acquisition status; land acquisition status; design and engineering status; events that might affect the ability to meet design specifications; status of contracts for project work, including land, procurement, and staffing; Interconnecting PTO or other entity interconnection agreements; construction status; testing status; risks and obstacles to project completion; and Project budget status, including actuals, estimate to complete, and contingency. The format for the report shall be in accordance with the Business Practice Manual for the Transmission Planning Process.

5.3.3 Pursuant to Section 24.6.1 of the CAISO Tariff, the CAISO will send Project status reports received in accordance with Section 5.3.2 to the applicable Interconnecting PTO and then the CAISO will hold a call with the Interconnecting PTO to review the status report, including completion date and items of concern.

5.3.4 If, at any time, the Approved Project Sponsor determines, in consultation with the CAISO and Interconnecting PTO or other entity providing Transmission Interconnection Service, that the completion of the Interconnecting PTO's or other entity’s Transmission Interconnection Facilities will not be required until after the specified energization date set forth in Appendix B (Milestones), the Approved Project Sponsor shall provide written notice to the Interconnecting PTO or other entity and to the CAISO of such later date upon which the completion of the Interconnecting PTO's or other entity’s Transmission Interconnection Facilities will be required.

5.4 Submission and Review of Project Specifications.

5.4.1 The Approved Project Sponsor shall submit specifications for major Project equipment and/or materials, including System Protection Facilities, to the CAISO and to the Interconnecting PTO or other entity providing Transmission Interconnection Service, for review and comment at least thirty (30) calendar days prior to the date on which the Approved Project Sponsor solicits offers to provide specific equipment or material to which the specifications apply or otherwise commences procurement. The

Approved Project Sponsor shall provide the CAISO and the Interconnecting PTO or other entity the opportunity to review such specifications to ensure that the Project is compatible with the technical specifications, operational control, safety requirements, and any other applicable requirements of the CAISO and the Interconnecting PTO or other entity providing Transmission Interconnection Service, and to provide comment on such specifications within fifteen (15) calendar days after the submission. All specifications provided hereunder shall be deemed Confidential Information subject to the provisions of Article 19.

5.4.2 The Approved Project Sponsor shall submit final specifications for major Project equipment and/or materials, including System Protection Facilities, if the specification differs from the specification submitted in accordance with Section 5.4.1, to the CAISO and to the Interconnecting PTO or other entity providing Transmission Interconnection Service, for review at least one hundred eighty (180) calendar days prior to the date that testing is scheduled to commence pursuant to Appendix B (Milestones). The Approved Project Sponsor shall submit to the CAISO and to the Interconnecting PTO or other entity providing Transmission Interconnection Service final specifications for review and comment at least ninety (90) calendar days prior to the date testing is scheduled to commence. If material and/or equipment is different from the original specification submittal, the Approved Project Sponsor shall provide the CAISO and the Interconnecting PTO or other entity the opportunity to review such specifications to ensure that the Project is compatible with the technical specifications, operational control, safety requirements, and any other applicable requirements and to provide comments within thirty (30) calendar days after each submission. All specifications provided hereunder shall be deemed Confidential Information subject to the provisions of Article 19.

5.4.3 Final specification review by the CAISO and by the Interconnecting PTO or other entity shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability, or reliability of the Project or the Interconnecting PTO's Transmission Interconnection Facilities. As described in Section 5.4.2, Approved Project Sponsor shall make such changes to the Project as may reasonably be required by the Interconnecting PTO, other entity, or the CAISO, in accordance with Good Utility Practice, to ensure that the Project is compatible with the technical specifications, Operational Control, and safety requirements of the Interconnecting PTO, other entity, or the CAISO.

5.5 Construction Activities.

5.5.1 The Approved Project Sponsor shall commence construction of the Project as soon as practicable, consistent with the schedule set forth in Appendix B (Milestones), after the following additional conditions are satisfied:

5.5.1.1 The Approved Project Sponsor has obtained appropriate Governmental Authority approval for any facilities requiring regulatory approval.

5.5.1.2 The Approved Project Sponsor has obtained necessary permits, real property rights, and rights-of-way, to the extent required for the construction of the Project.

5.5.2 At least thirty (30) calendar days prior to commencement of Project construction, the Approved Project Sponsor shall provide to the CAISO, for informational purposes, a construction schedule for the Interconnecting PTO's or other entity's Transmission Interconnection Facilities.

5.5.3 At any time during construction, should any phase of the Project engineering, equipment procurement, or construction not meet the standards and specifications provided by the Interconnecting PTO or other entity, the Approved Project Sponsor shall be obligated to remedy deficiencies in that portion of the Project. The Approved Project Sponsor may seek approval from FERC to recover in its transmission revenue requirement just and reasonable costs associated with such remedy.

5.5.4 The Approved Project Sponsor shall indemnify the CAISO for claims arising under this Agreement resulting from Project construction under the terms and procedures specified in Section 15.1 Indemnity, other than for losses arising from actions that are not within the control of the Approved Project Sponsor.

5.5.5 If, during Project development, siting, design, engineering, construction, or testing, the Approved Project Sponsor decides to use a vendor, or any other Project team member, that is different than the vendor or team member specifically set forth in the Project Sponsor proposal submitted by the Approved Project Sponsor in accordance with the Business Practice Manual for the Transmission Planning Process, the Approved Project Sponsor shall notify the CAISO within ten (10) calendar days after the decision to make the change. Upon notification, the CAISO may take whatever action is necessary to ensure that the selected vendor or Project team member will at a minimum provide the same level of service that would have been provided by the vendor or Project team member described in the Approved Project Sponsor's proposal.

5.6 Final Project Design

5.6.1 As soon as reasonably practicable, but within twelve months after Project construction completion, the Approved Project Sponsor shall provide a summary of the final construction cost, which summary shall set forth sufficient detail to enable the CAISO to understand the Project costs, including a written explanation for the use of contingency and any cost overruns in excess of the cost estimate provided in Appendix E.

5.6.2 The Project shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) calendar days after the Project has been turned over to the CAISO's Operational Control, unless the CAISO and Approved Project Sponsor agree on another mutually acceptable date, the Approved Project Sponsor shall deliver to the Interconnecting PTO or other entity and to the CAISO "as-built" drawings, information, and documents for the Project. This information shall include, as applicable: (i) a one-line diagram; (ii) a site plan drawing showing the Project, including plan and elevation drawings showing the layout of the Transmission Interconnection Facilities; (iii) a relay functional diagram, relaying AC and DC schematic wiring diagrams, and relay settings for all facilities associated with the Project; and (iv) the impedances, determined by factory tests, for the associated transformers. The Approved Project Sponsor shall provide the Interconnecting PTO or other entity and the CAISO specifications for the protection settings, transformer tap settings, and communications, if applicable. The Interconnecting PTO or other entity and the CAISO shall assess any deviations from the relay settings, machine specifications, and other specifications originally submitted by the Approved Project Sponsor pursuant to the appropriate provisions of this Agreement and the agreement between the Approved Project Sponsor and the Interconnecting PTO or other entity.

5.6.3 The obligations under this Section 5.6, including Sections 5.6.1, 5.6.2, and 5.6.3, shall survive termination of this Agreement.

5.7 **Delay in Project.** If the CAISO receives notification from the Approved Project Sponsor that Project energization will be delayed beyond the date by which the CAISO found the Project to be needed, pursuant to Section 24.6.2 of the CAISO Tariff the CAISO shall issue a market notice to market participants stating that the Project is delayed. If applicable, the market notice shall also state that a plan is being developed to address potential NERC reliability standard violations as set forth in Section 24.6.3 of the CAISO Tariff, as well as any material concerns.

5.7.1 The CAISO shall determine if there is a potential NERC violation, for either the CAISO or applicable Interconnecting PTO, arising from any Project energization delay and will determine if there are other material issues of concern as required in accordance with Section 24.6.3 of the CAISO

Tariff. If there are potential violations or material issues, the CAISO, Approved Project Sponsor, and applicable Interconnecting PTO shall develop a plan to address the delay. The plan may include the CAISO directing the Interconnecting PTO to develop a mitigation plan.

5.7.2 If violations or material issues cannot be promptly and adequately addressed, the CAISO will take action to resolve the issues, including determining if an alternative Project Sponsor is required.

5.8 Delay in Approvals, Property Acquisition, or Construction. If the timeline set forth in Appendix B is unreasonably delayed, the CAISO shall consult with the Approved Project Sponsor. After such consultation, should the CAISO determine that, for reasons other than a delay caused by the Interconnecting PTO, (i) the Approved Project Sponsor cannot secure necessary approvals or property rights, including fee title, right of way grant, and easement and license rights, essential for construction of the Project, or (ii) the Approved Project Sponsor is otherwise unable to timely construct the Project, or (iii) an alternative Project Sponsor is necessary pursuant to Section 24.6.4 of the CAISO Tariff; or, alternatively, if the Approved Project Sponsor determines that it is unable to proceed with construction and so notifies the CAISO, the CAISO shall take such action, including termination of this Agreement, as it determines to be necessary and appropriate in accordance with Section 24.6.4 of the CAISO Tariff. If either Party determines that an alternative Project Sponsor should be selected consistent with Section 24.6.4 of the CAISO Tariff, the Approved Project Sponsor agrees to work in good faith with CAISO, the alternative Project Sponsor, and, if applicable, the Interconnecting PTO to transfer responsibility for the Project to the alternative Project Sponsor.

5.9 Modification.

5.9.1 The Approved Project Sponsor may undertake modifications to its facilities only with the approval of the CAISO and subject to the provisions of this Agreement and the CAISO Tariff. If the Approved Project Sponsor plans to undertake a modification, it shall provide such information regarding such modification to the CAISO as the CAISO deems necessary to evaluate the potential impact of such modification prior to commencement of the work. Such information shall include information concerning the timing of such modification, any technical information, and cost impact. The Approved Project Sponsor shall provide the relevant drawings, plans, and specifications to the CAISO at least ninety (90) calendar days in advance of the commencement of the work or within such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned, or delayed. The CAISO shall determine if a modification is in accordance with the original Project criteria and intent and whether to approve the modification within thirty (30) calendar days after the Approved Project Sponsor's submission.

5.9.2 Any additions, modifications, or replacements made to the Project's facilities shall be designed, constructed, and operated in accordance with this Agreement, Applicable Laws and Regulations, and Good Utility Practice.

5.9.3 Any modifications to the Project's facilities ordered by a siting agency are not subject to CAISO approval. However, the Approved Project Sponsor is required to notify the CAISO within thirty (30) calendar days after the siting agency has issued an order directing Project modifications.

5.10 Generator Interconnection Study Process.

5.10.1 The Approved Project Sponsor shall be responsible for completing any existing studies for generator interconnection to the Project that were in the Approved Project Sponsor's generation interconnection queue upon the Effective Date of this Agreement. The CAISO and any impacted Participating TO will perform studies regarding such requests as an Affected System.

5.10.2 Any requests for generation interconnection to the Project submitted to the Approved Project Sponsor following the Effective Date of this Agreement shall be directed to the CAISO Interconnection Request process. The Approved Project Sponsor shall assume the functions of a Participating TO in accordance with Appendix DD of the CAISO Tariff, including performing Phase I, Phase II, and reassessment analysis for generator interconnection requests to the Project. The Approved Project Sponsor will be reimbursed the actual costs incurred for the analysis similar to the Participating TOs.

5.10.3 Any Generator Interconnection Agreements for interconnection to the Project shall be executed consistent with the relevant terms and conditions of the CAISO Tariff.

5.10.4 The obligations under this Section 5.10, including Sections 5.10.1, 5.10.2, 5.10.3, and 5.10.4 shall survive termination of this Agreement.

5.11 Planning Authority. The CAISO is the Planning Authority, as that term is defined by NERC, for the Project from the time it is identified in the CAISO's Transmission Planning Process and approved by the CAISO Governing Board, regardless of the status of Project construction or energization. As such, the Approved Project Sponsor shall be subject to the rights and obligations set forth in CAISO Tariff Section 24 that are applicable to Participating TOs as they pertain to the Project.

5.12 Tax Status. Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Agreement is intended to adversely affect the CAISO's or the Approved Project Sponsor's tax exempt status with respect to the issuance of bonds, including Local Furnishing Bonds, if any.

ARTICLE 6. TESTING AND INSPECTION

6.1 Testing and Modifications. Prior to energizing the Project for testing, the Interconnecting PTO or other entity shall test the Interconnecting PTO's or other entity's Transmission Interconnection Facilities, and the Approved Project Sponsor shall test the Project to ensure their safe and reliable operation. All testing shall be coordinated and approved by the CAISO to ensure grid reliability. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. The Approved Project Sponsor shall not commence initial parallel operation of the Project until the Interconnecting PTO or other entity provides prior written approval to the CAISO and the Approved Project Sponsor.

6.2 Right to Observe Testing. The Approved Project Sponsor shall notify the CAISO at least fourteen (14) calendar days in advance of its performance of tests. The CAISO has the right, at its own expense, to observe such testing.

6.3 Right to Inspect. The CAISO shall have the right, but shall have no obligation, to (i) observe the Approved Project Sponsor's tests and/or inspection of any of its System Protection Facilities and other protective equipment; and (ii) review the settings of the Approved Project Sponsor's System Protection Facilities and other protective equipment at its expense. The CAISO may exercise these rights from time to time as it deems necessary upon reasonable notice to the Approved Project Sponsor. The exercise or non-exercise by CAISO of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Project or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that CAISO obtains through the exercise of any of its rights under this Section 6.3 shall be deemed to be Confidential Information and treated pursuant to Article 19 of this Agreement.

ARTICLE 7. METERING

7.1 General. The Approved Project Sponsor shall comply with any Applicable Reliability Standards and the Applicable Reliability Council requirements regarding metering. The Approved Project Sponsor and CAISO shall comply with the provisions of the CAISO Tariff regarding metering, including Section 10 of the CAISO Tariff. Power flows to and from the Project shall be measured at or, at the CAISO's option for its respective Metering Equipment, compensated to, the Scheduling Point. The CAISO shall provide metering quantities to the Approved Project Sponsor upon request in accordance with the CAISO Tariff by directly polling the CAISO's meter data acquisition system. The Approved Project Sponsor shall bear all reasonable documented costs associated with the purchase, installation, operation, testing, and maintenance of the Metering Equipment.

ARTICLE 8. COMMUNICATIONS

8.1 Approved Project Sponsor Obligations. The Approved Project Sponsor shall maintain satisfactory operating communications with the CAISO in accordance with the provisions of the CAISO Tariff and with the Interconnecting PTO's or other entity's dispatcher or such other representative designated by the Interconnecting PTO or other entity during synchronization, testing, and energization. The Approved Project Sponsor shall provide standard voice line, dedicated voice line, and facsimile communications at the Project's control room or central dispatch facility through use of either the public telephone system or a voice communications system that does not rely on the public telephone system. The Approved Project Sponsor shall also provide the dedicated data circuits necessary to provide Approved Project Sponsor data to the CAISO and Interconnecting PTO as set forth in Appendix C, Security Arrangements Details. The data circuits shall extend from the Project to the locations specified by the CAISO and Interconnecting PTO. Any required maintenance of such communications equipment shall be performed by the Approved Project Sponsor. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, and equipment clearances.

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with Applicable Reliability Standards and the Applicable Reliability Council operating requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 CAISO Obligations. The CAISO shall cause the Interconnecting PTO's transmission system to be operated and controlled in a safe and reliable manner during testing and synchronization and before the Approved Project Sponsor turns the Project over to CAISO Operational Control. The CAISO may provide operating instructions to the Approved Project Sponsor consistent with this Agreement and the Interconnecting PTO's and CAISO's operating protocols and procedures as they may change from time to time. The Interconnecting PTO and CAISO will consider changes to their operating protocols and procedures proposed by the Approved Project Sponsor.

9.3 Approved Project Sponsor Obligations. The Approved Project Sponsor shall at its own expense operate, maintain, and control the Project in a safe and reliable manner and in accordance with this Agreement in advance of turning over Operational Control to the CAISO. Appendix A, Project Details, sets forth applicable requirements of the CAISO Balancing Authority Area and may be modified by mutual agreement of the Parties to reflect changes to the requirements as they may change from time to time. The Approved Project Sponsor shall not energize the Project with the Interconnecting PTO's or other entity's transmission system until the Interconnecting PTO or other entity provides prior written approval.

9.4 Start-Up and Synchronization. The Parties shall establish agreed procedures for start-up, testing, and energization of the Project to the CAISO Controlled Grid prior to start-up of the Project. The Approved Project Sponsor shall be responsible for proper start-up and energization of the Project in compliance with the established procedures.

ARTICLE 10. COST RECOVERY, BILLING, AND PAYMENT

10.1 Transmission Revenue Requirement. The Approved Project Sponsor may apply to FERC for a Transmission Revenue Requirement for transmission facilities not yet in operation, but approved under the transmission planning provisions of the CAISO Tariff, that will be Regional Transmission Facilities or Local Transmission Facilities when placed under the CAISO's Operational Control. If FERC approves such Transmission Revenue Requirement, the CAISO shall incorporate the Transmission Revenue Requirement into the Regional Access Charge or Local Access Charge in accordance with the CAISO Tariff. The Approved Project Sponsor acknowledges and agrees with the cost estimates and the binding cost cap, or other binding cost containment measures, if applicable, set forth in Appendix E.

10.1.1 The Approved Project Sponsor agrees that it shall not seek, for recovery through its Transmission Revenue Requirement, higher costs than the maximum costs specified in, or determined in accordance with, any cost cap or other binding cost containment measures as specified in Appendix E except for costs incurred to comply with any additional specifications of the CAISO or Interconnecting PTO beyond the functional requirements for the transmission facility that the CAISO issued for the competitive solicitation. The Approved Project Sponsor shall not seek recovery through its Transmission Revenue Requirement of any incentives or other costs that it has agreed to forego, as specified in Appendix E. The Approved Project Sponsor further agrees that the Transmission Control Agreement shall incorporate the Project cost cap or any other agreed-to binding cost containment measures agreed to or proposed by the Approved Project Sponsor. The provisions of this Section 10.1.1 shall survive termination of this Agreement.

10.2 Application of CAISO Tariff. The CAISO and Approved Project Sponsor shall comply with the billing and payment provisions set forth in the CAISO Tariff.

10.3 Refund Obligation. The Approved Project Sponsor, whether or not it is subject to FERC rate jurisdiction under Section 205 and Section 206 of the Federal Power Act, shall make all refunds, adjustments to its Transmission Revenue Requirement, and adjustments to its Approved Project Sponsor Tariff, and do all other things required to implement any FERC order related to the CAISO Tariff, including any FERC order the implementation of which necessitates the CAISO making payment adjustments or paying refunds to, or receiving prior period overpayments from, the Approved Project Sponsor. All such refunds and adjustments shall be made, and all other actions taken, in accordance with the CAISO Tariff, unless the applicable FERC order requires otherwise. These obligations under this Section 10.3 shall survive termination of this Agreement.

ARTICLE 11. REGULATORY REQUIREMENTS AND GOVERNING LAWS

11.1 Regulatory Requirements. Each Party's obligations under this Agreement shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, and compliance with the prior notice requirements of such Governmental Authorities. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this Agreement shall require the Approved Project Sponsor to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act or the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978, or the Energy Policy Act of 2005.

11.2 Governing Law.

11.2.1 The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the state of California, without regard to its conflicts of law principles.

11.2.2 This Agreement is subject to all Applicable Laws and Regulations.

11.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

ARTICLE 12. NOTICES

12.1 General. Unless otherwise provided in this Agreement, any notice, demand, or request required or permitted to be given by a Party to another and any instrument required or permitted to be tendered or delivered by a Party in writing to another shall be effective when delivered and may be so given, tendered, or delivered by (i) recognized national courier, (ii) depositing the same with the United States Postal Service with postage prepaid for delivery by certified or registered mail, addressed to the Party, or (iii) personal delivery to the Party, at the address set out in Appendix D, Addresses for Delivery of Notices and Billings.

A Party must update the information in Appendix D as information changes. A Party may change the notice information in this Agreement by giving five (5) Business Days written notice prior to the effective date of the change. Such changes shall not constitute an amendment to this Agreement.

12.2 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to another and not required by this Agreement to be given in writing may be given by telephone, facsimile, or e-mail to the telephone numbers and e-mail addresses set out in Appendix D.

12.3 [Intentionally left blank.]

12.4 Operations Notice. Each Party shall notify the other Party in writing of the identity of the person that it designates as the point of contact with respect to the implementation of Article 9.

12.5 Project Management. If the Approved Project Sponsor desires to change the identified project management, including key personnel, the Approved Project Sponsor shall notify the CAISO in writing thirty (30) calendar days in advance for approval. Such approval shall not be unreasonably withheld.

12.6 Notice of Regulatory Filings. The Approved Project Sponsor will provide to the CAISO, Participating TOs (as listed on Appendix F to the Transmission Control Agreement), and other Approved Project Sponsors, a copy of all initial filings it submits in a FERC docket that affects the rates (including Transmission Revenue Requirement), terms, or conditions of service for the Project. The Approved Project Sponsor will provide such copy either via email or first-class U.S. mail on the same day it makes the filing with FERC; provided that if the copy is sent via U.S. mail, the requirement will be satisfied if the Approved Project Sponsor places the copy in the mail on the date of filing. The CAISO will post the contact information for Approved Project Sponsors on the CAISO website.

ARTICLE 13. FORCE MAJEURE

13.1 Force Majeure.

13.1.1 No Party shall be considered to be in Default with respect to any obligation hereunder if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Section shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

13.1.2 If required, the Parties shall revise this Agreement, including Appendix B and Appendix E, following a Force Majeure event.

ARTICLE 14. DEFAULT

14.1. General. No Default shall exist where failure to discharge an obligation, other than the payment of money, is the result of Force Majeure as defined in this Agreement or the result of an act or omission of the other Party. Upon a Breach, the affected non-Breaching Party shall give written notice of such Breach to the Breaching Party. The Breaching Party shall have thirty (30) calendar days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) calendar days, the Breaching Party shall commence such cure within thirty (30) calendar days after notice and continuously and diligently complete such cure within ninety (90) calendar days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

14.2 Right to Terminate. If a Breach is not cured as provided in this Article, or if a Breach is not capable of being cured within the period provided for herein, the affected non-Breaching Party shall have the right to declare a Default and terminate this Agreement by written notice at any time until cure occurs and be relieved of any further obligation hereunder and, whether or not such Party terminates this Agreement, to recover from the Breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article shall survive termination of this Agreement.

14.3 Notice to Financing Parties. If, as contemplated by Section 16.1, the Approved Project Sponsor has provided notice to the CAISO of an assignment of this Agreement for collateral security purposes to aid in providing financing for the Project, then (a) if such notice of collateral assignment so indicates and contains notice information for the collateral assignee, the CAISO shall provide a copy to collateral assignee identified in such notice of any notice of Breach given by the CAISO to the Approved Project Sponsor and (b) such collateral assignee shall have the right, but no obligation, to effect cure of the Breach on behalf of the Approved Project Sponsor, and any performance of any obligations under this Agreement by such collateral assignee shall be accepted by the CAISO to the same extent as though the Approved Project Sponsor had directly performed such obligations.

ARTICLE 15. INDEMNITY, CONSEQUENTIAL DAMAGES, AND INSURANCE

15.1 Indemnity. Each Party (the "Indemnifying Party") shall at all times indemnify, defend, and hold the other Party (the "Indemnified Party") harmless from any and all Losses arising out of or resulting from the Indemnifying Party's action or inactions of its obligations under this Agreement, except in cases of negligence or intentional wrongdoing by the Indemnified Party.

15.1.1 Indemnified Party. If the Indemnified Party is entitled to indemnification under this Article 15 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Section 15.1 to assume the defense of such claim, such Indemnified Party may at the expense of the Indemnifying Party contest, settle, or consent to the entry of any judgment with respect to, or pay in full, such claim.

15.1.2 Indemnifying Party. If the Indemnifying Party is obligated to indemnify and hold the Indemnified Party harmless under this Article 15, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual Loss, net of any insurance or other recovery.

15.1.3 Indemnity Procedures. Promptly after receipt by the Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Section 15.1 may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by the Indemnifying Party and reasonably satisfactory to the Indemnified Party. If the defendants in any such action include the Indemnified Party and the Indemnifying Party and if the Indemnified Party reasonably concludes that there may be legal defenses available to it that are different from or additional to those available to the Indemnifying Party, the Indemnified Party shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Party having such differing or additional legal defenses.

The Indemnified Party shall be entitled, at its expense, to participate in any such action, suit, or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit, or proceedings if and to the extent that, in the opinion of the Indemnified Party and its counsel, such action, suit, or proceeding involves the potential imposition of criminal liability on the Indemnified Party, or there exists a conflict or adversity of interest between the Indemnified Party and the Indemnifying Party, in which event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Party, and (ii) shall not settle or consent to the entry of any judgment in any action, suit, or proceeding without the consent of the Indemnified Party, which shall not be unreasonably withheld, conditioned, or delayed.

15.2 Consequential Damages. In no event shall any Party be liable under any provision of this Agreement for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including loss of profit or revenue, loss of the use of equipment, cost of capital, or cost of temporary equipment or services, whether based in whole or in part in contract or in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement shall not be considered to be special, indirect, incidental, or consequential damages hereunder.

15.3 Insurance. The Approved Project Sponsor shall carry insurance for the Project in accordance with good utility practice.

15.4 Continuity of Obligations. The obligations and liability limitations under this Article 15 shall survive termination of the Agreement.

ARTICLE 16. ASSIGNMENT

16.1 Assignment. With the exception of assignment for collateral security purposes in accordance with this Section and Section 14.3, this Agreement may be assigned by a Party only with the written consent of the other Party, which consent shall not be unreasonably withheld. The CAISO will not approve the assignment unless the assignee (i) meets the competitive solicitation qualification requirements set for in CAISO Tariff Section 24.5.3.1; (ii) agrees to honor the cost containment measures or cost caps specified in Appendix E, if applicable; (iii) agrees to meet the factors that the CAISO relied upon in selecting the Approved Project Sponsor; and (iv) assumes the rights and obligations contained in this Agreement; provided, however, that the Approved Project Sponsor shall have the right to assign this Agreement, without the consent of the CAISO, for collateral security purposes to aid in providing financing for the Project, provided that the Approved Project Sponsor shall promptly notify the CAISO of any such assignment, including identification of the assignee and contact information. Any financing arrangement entered into by the Approved Project Sponsor pursuant to this Article shall provide that prior to or upon the exercise of the secured party's, trustee's, or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee, or mortgagee shall notify the CAISO of the date and particulars of any such exercise of assignment rights. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof.

ARTICLE 17. SEVERABILITY

17.1 Severability. If any provision in this Agreement is finally determined to be invalid, void, or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement, or covenant of this Agreement.

ARTICLE 18. COMPARABILITY

18.1 Comparability. The Parties shall comply with all applicable comparability and code of conduct laws, rules, and regulations, as amended from time to time.

ARTICLE 19. CONFIDENTIALITY

19.1 Confidentiality. Confidential Information shall include all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by a Party to the other Party prior to the execution of this Agreement.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by a Party, the other Party shall provide in writing the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

19.1.1 Term. During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article, each Party shall hold in confidence and shall not disclose Confidential Information to any person.

19.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known through no wrongful act or omission of the receiving Party or Breach of this Agreement; or (6) is required, in accordance with Section 19.1.7 of this Agreement, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information shall no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

19.1.3 Release of Confidential Information. No Party shall release or disclose Confidential Information to any other person, except to its employees, consultants, Affiliates (limited by the Standards of Conduct requirements set forth in Part 358 of FERC's regulations, 18 C.F.R. Section 358), and subcontractors, or to parties who may be or considering providing financing to or equity participation with the Approved Project Sponsor, or to potential purchasers or assignees of the Approved Project Sponsor, on a need-to-know basis in connection with this Agreement, unless such person has first been advised of the confidentiality provisions of this Article and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article.

19.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

19.1.5 No Warranties. The mere fact that a Party has provided Confidential Information does not constitute a warranty or representation as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to the other Party or to enter into any further agreements or proceed with any other relationship or joint venture.

19.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication, or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this Agreement or its regulatory requirements.

19.1.7 Order of Disclosure. If a court or another Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request or requirement so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party shall use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

19.1.8 Termination of Agreement. Upon termination of this Agreement for any reason, each Party shall, within ten (10) calendar days after receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete, with such destruction, erasure, and deletion certified in writing to the other Party, or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party, unless subject to retention for litigation or regulatory purposes.

19.1.9 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article.

19.1.10 Disclosure to FERC, its Staff, or a State. Notwithstanding anything in this Article to the contrary, and pursuant to 18 C.F.R. Section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. A Party is prohibited from notifying the other Party prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

19.1.11 Subject to the Exception in Section 19.1.10. Subject to the exception in Section 19.1.10 and consistent with the provisions of Sections 19.1.3 and 19.1.7, Confidential Information shall not be disclosed by a Party to any person not employed or retained by that Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Agreement or as a transmission service provider or a Balancing Authority including disclosing the Confidential Information to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of another Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this Section 19.1.11, the disclosing Party shall promptly notify the other Party in writing and shall assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order, or other reasonable measures.

ARTICLE 20. ENVIRONMENTAL RELEASES

20.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, including hazardous wastes as defined by local, state, and federal law, any asbestos or lead abatement activities, or any type of remediation activities related to the Project or the Transmission Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (i) provide the notice as soon as practicable, for an occurrence that may present an immediate risk to human health or the environment; (ii) make a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence for an event that may present an immediate risk to human health or the environment; and (iii) promptly furnish to the other Party information necessary for the designated Party to notify any Governmental Authorities of the event as required by law or Project-specific conditions. Copies of any publicly available reports shall be distributed to the other Party regarding such events.

ARTICLE 21. INFORMATION ACCESS AND AUDIT RIGHTS

21.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this Agreement; and (ii) carry out its obligations and responsibilities under this Agreement. The Parties shall not use such information for purposes other than those set forth in this Section 21.1 and to enforce their rights under this Agreement. Nothing in this Article shall obligate the CAISO to make available to a Party any third party information in its possession or control if making such third party information available would violate a CAISO Tariff restriction on the use or disclosure of such third party information.

21.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this Agreement for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation, or information provided under this Section shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this Agreement.

21.3 Audit Rights. Subject to the requirements of confidentiality under Article 19 of this Agreement, the CAISO audit rights shall include the CAISO's right to audit the Approved Project Sponsor's costs pertaining to performance or satisfaction of obligations under this Agreement.

21.3.1 The CAISO shall have the right, during normal business hours, and upon prior reasonable notice to the Approved Project Sponsor, to audit at its own expense the accounts and records pertaining to satisfaction of obligations under this Agreement. Subject to Section 21.3.2, any audit authorized by this Section 21.3 shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to performance and satisfaction of obligations under this Agreement. The Approved Project Sponsor shall keep such accounts and records for a period equivalent to the audit rights periods described in Section 21.4.

21.3.2 Notwithstanding anything to the contrary in this Agreement, the Approved Project Sponsor's rights to audit the CAISO's accounts and records shall be as set forth in Section 22.1 of the CAISO Tariff.

21.4 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Project constructed by the Approved Project Sponsor shall be subject to audit and verification by the CAISO for a period of twenty-four months following the issuance of a final cost summary in accordance with Section 5.6.1.

ARTICLE 22. SUBCONTRACTORS

22.1 General. Subject to Section 5.5.5, nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services, and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

22.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the CAISO be liable for the actions or inactions of the Approved Project Sponsor or its subcontractors with respect to obligations of the Approved Project Sponsor under Article 4 of this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

ARTICLE 23. DISPUTES

23.1 General. All disputes arising out of or in connection with this Agreement whereby relief is sought by or from the CAISO shall be settled in accordance with the provisions of Section 13 of the CAISO Tariff, except that references to the CAISO Tariff in such Section 13 of the CAISO Tariff shall be read as references to this Agreement. Disputes arising out of or in connection with this Agreement not subject to provisions of Section 13 of the CAISO Tariff shall be resolved as follows:

23.2 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this Agreement or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) calendar days after the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this Agreement.

23.3 External Arbitration Procedures. Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) calendar days after the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) calendar days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration, except prior arbitration. The arbitrator shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article, the terms of this Article shall prevail.

23.4 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator shall render a decision within ninety (90) calendar days after appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator may be appealed solely on the grounds that the conduct of the arbitrator, or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with, and approved by, FERC if it affects jurisdictional rates, terms, and conditions of service, Transmission Interconnection Facilities, or Network Upgrades.

23.5 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

ARTICLE 24. REPRESENTATIONS, WARRANTIES, AND COVENANTS

24.1 General. Each Party makes the following representations, warranties, and covenants:

24.1.1 Good Standing. Such Party is duly organized, validly existing, and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Project and transmission facilities owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted, and to enter into this Agreement and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

24.1.2 Authority. Such Party has the right, power, and authority to enter into this Agreement, to become a Party hereto, and to perform its obligations hereunder. This Agreement is a legal, valid, and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, or other similar laws affecting creditors' rights generally and by general equitable principles, regardless of whether enforceability is sought in a proceeding in equity or at law.

24.1.3 No Conflict. The execution, delivery, and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement, or instrument applicable to or binding upon such Party or any of its assets.

24.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Agreement, will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery, and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

24.1.5 Technical Specifications Accurate. The technical specifications provided by the Approved Project Sponsor to the CAISO are accurate and complete.

ARTICLE 25. MISCELLANEOUS

25.1 Binding Effect. This Agreement and the rights and obligations hereof shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

25.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices, or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

25.3 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement, including this Agreement, document, instrument, or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section, or Appendix means such Article or Section of this Agreement or such Appendix to this Agreement, or such Section of the CAISO Tariff or such Appendix to the CAISO Tariff, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Article, Section, or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

25.4 Entire Agreement. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Agreement.

25.5 No Third Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest, and, where permitted, their assigns.

25.6 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement shall not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of this Agreement. Termination or Default of this Agreement for any reason by the Approved Project Sponsor shall not constitute a waiver of the Approved Project Sponsor's legal rights to obtain an interconnection from the CAISO. Any waiver of any provision of this Agreement shall, if requested, be provided in writing.

25.7 Headings. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

25.8 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all of which constitute one and the same instrument.

25.9 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

25.10 Modification by the Parties. Except as described in Appendices B and E, the Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

25.11 Reservation of Rights. The CAISO has the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to any rates, terms and conditions, charges, classifications of service, rule, or regulation. The Approved Project Sponsor shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations. Each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered.

25.12 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

25.13 Joint and Several Obligations. Except as otherwise provided in this Agreement, the obligations of the CAISO and the Approved Project Sponsor are several, and are neither joint nor joint and several.

IN WITNESS WHEREOF, the Parties have executed this Agreement in multiple originals, each of which shall constitute and be an original effective agreement between the Parties.

Horizon West Transmission, LLC

By: DocuSigned by: Jaime Hoffman
B4192ACE7247448...

Name: Jaime Hoffman

Title: President

Date: 12/29/2024

California Independent System Operator Corporation

By: DocuSigned by: Deborah A. Le Vine
FD37AE0BAAF54EC...

Name: Deborah A. Le Vine

Title: Executive Director

Date: 12/27/2024

Appendices to Agreement

Appendix A	Project Details
Appendix B	Milestones
Appendix C	Security Arrangements Details
Appendix D	Addresses for Delivery of Notices and Billings
Appendix E	Approved Project Sponsor's Costs of Project

Appendix A

Project Details

1. Description

In the 2022-2023 Transmission Plan, the ISO has identified a policy-driven need for the North Gila – Imperial Valley #2 500 kV Line Project as part of the Southern Area Reinforcement Projects. Figure I.3-1 provides a schematic diagram of the transmission system in the area. As shown in the figure, the project scope includes a new 500 kV circuit between North Gila and Imperial Valley substations.

Figure I.3-1: Location of North Gila – Imperial Valley #2 500 kV Line Project

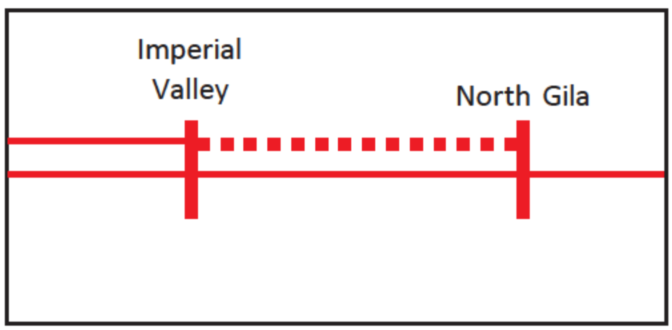
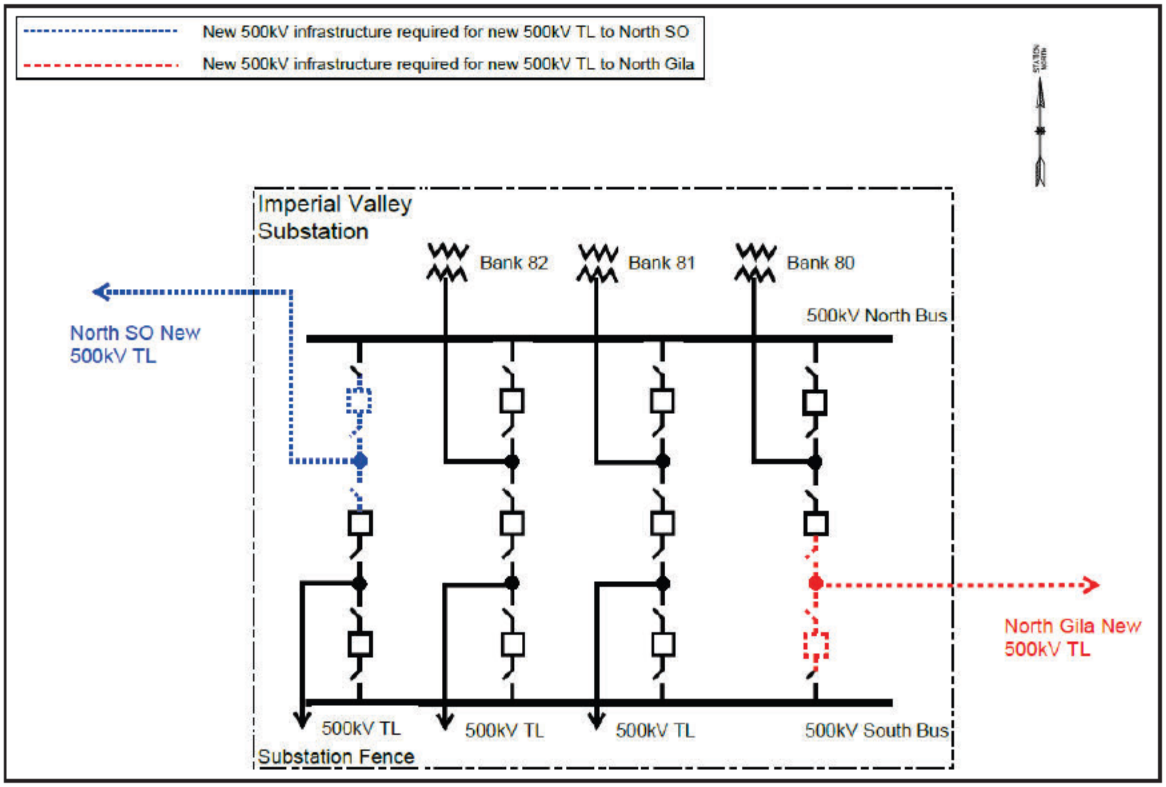
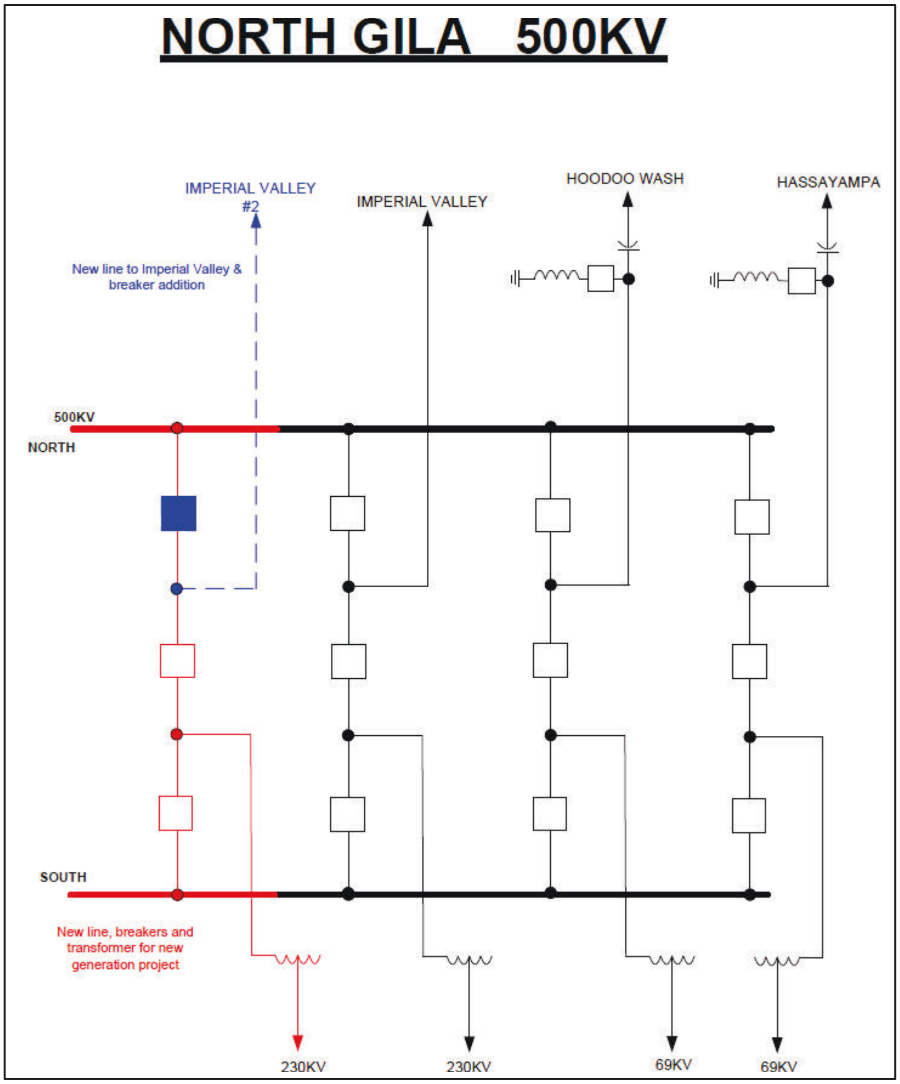


Figure I.3-2 provides a schematic diagram of the interconnection to North Gila and Imperial Valley 500 kV substations.

Figure I.3-2: Interconnection to North Gila 500 kV and Imperial Valley 500 kV





The facilities in the North Gila – Imperial Valley #2 500 kV Line project that are eligible for competitive solicitation are the new 500 kV line from North Gila to Imperial Valley substation.

For the interconnection of the North Gila – Imperial Valley #2 500 kV Line to the Imperial Valley substation, the San Diego Gas & Electric Company (SDG&E), will be responsible for installing the new transmission line segments from the Imperial Valley 500 kV bus up to a point within 100 feet of the Imperial Valley substation property line (or other location agreed to by Approved Project Sponsor, CAISO and SDG&E). This new line segments will terminate on a dead-end structure(s), to be owned by SDG&E. The Approved Project Sponsor will be responsible for (and will own and maintain) the facilities from this last dead-end structure(s) back to the North Gila Substation.

For the interconnection of the North Gila – Imperial Valley #2 500 kV Line to the North Gila substation, Arizona Public Service Company (APS) will be responsible for installing the new transmission line segments from the North Gila 500 kV bus up to a point within 100 feet of the North Gila substation property line (or other location agreed to by APS, CAISO and Approved Project Sponsor) and line shunt reactors. This new line segments will terminate on a dead-end structure(s), to be owned by APS. The Approved Project Sponsor will be responsible for (and will own and maintain) the facilities from this last dead-end structure(s) back to the Imperial Valley substation.

The Approved Project Sponsor will coordinate with SDG&E and APS for the specifications and the details of the associated line protection (e.g., current differential, directional comparison, etc.) to develop relay logic and detailed relay settings.

As the Project includes building a new transmission facility with a voltage level over 200 kV, the Approved Project Sponsor will be responsible for completing the WECC Progress Report and other processes required for this Project.

2. Transmission Interconnection Facilities
None

3. Network Upgrades

500 kV Transmission Line Functional Specifications

Overhead Line Construction

Line Terminus 1: North Gila Substation 500 kV Bus

Line Terminus 2: Imperial Valley Substation 500 kV Bus

Nominal Phase to Phase Voltage: 525 kV

Minimum Line Continuous Ampacity - Summer: 3,194 Amps

Minimum Line Continuous Ampacity – Winter: 3,194 Amps

Minimum Line 4 Hour Emergency Ampacity – Summer: 3,194 Amps

Minimum Line 4 Hour Emergency Ampacity – Winter: 3,194 Amps

Approximate Line Impedance: 0.00088 + 0.02019 pu or 0.00157 + 0.01862 pu (100 MVA base).

Approximate Line Length: 82 miles

CAISO Required In Service Date: June 1, 2032

Support Structures: Single circuit structure

Shield Wire Required: Optical ground wire (minimum 24 pairs of fibers)

Failure Containment Loading Mitigation (anti-cascade structures, etc.): Per applicable codes

Shield Wire Ground Fault Withstand Ampacity: Coordinate with interconnecting entities

Aeolian Vibration Control (Conductor and Shield Wire): Vibration dampers must be installed on all conductors and overhead shield wires, with the exception of slack spans.

Transmission Line Minimum BIL: 1800 kV with solidly grounded systems

Minimum ROW Width: Per applicable codes

Governing Design and Construction Standards: (GO 95, NESC Code, applicable municipal codes)

Design Temperature: 50°C

4. Distribution Upgrades

None

5. Project Team:

Executive Director: Jacquelyn Blakley

Regional Director: Fred Bauermeister

Project Manager, Late-Stage: Derrik Berg

Project Manager, Early-Stage: Eric Oesterling

Land and GIS Team: Sarah Powers

Environmental: Jennifer Field

Engineering Construction and Controls Lead: Mike Piersall

Appendix B
Milestones

1. **Milestone Dates**

Item	Milestone	Responsible Party	Due Date 1/
1	Commence procurement including material and resources	Approved Project Sponsor	June 20, 2024**
2	Commence engineering design	Approved Project Sponsor	July 10, 2024**
3	Submit request for Transmission Interconnection Service to the applicable Interconnecting PTO	Approved Project Sponsor	July 29, 2024**
4	Commence development activities including commencement of regulatory approvals; acquisition of land; and permits	Approved Project Sponsor	July 29, 2024**
5	Submit Construction Plan in accordance with Section 5.3.1 of this Agreement	Approved Project Sponsor	November 7, 2024 **
6	Submit Construction Plan Status Report in accordance with Section 5.3.2 of this Agreement	Approved Project Sponsor	November 7, 2024** February 5, 2025** May 6, 2025** August 4, 2025** November 2, 2025** January 31, 2026** May 1, 2026** July 30, 2026** October 28, 2026** January 26, 2027** April 26, 2027**
7	Submit Project specifications in accordance with Section 5.4.1 of this Agreement	Approved Project Sponsor	July 9, 2027**
8	Submit Construction Plan Status Report in accordance with Section 5.3.2 of this Agreement	Approved Project Sponsor	July 25, 2027** October 23, 2027** January 21, 2028** April 20, 2028** July 19, 2028** October 17, 2028**

Item	Milestone	Responsible Party	Due Date 1/
9	Provide comments on Project specifications in accordance with Section 5.4.1 of this Agreement	CAISO	Response within 15 CD of request
10	Complete engineering design	Approved Project Sponsor	November 13, 2028**
11	Submit Construction Plan Status Report in accordance with Section 5.3.2 of this Agreement	Approved Project Sponsor	January 15, 2029** April 15, 2029**
12	Complete permitting activities in accordance with Section 5.5.1.1 of this Agreement	Approved Project Sponsor	April 16, 2029**
13	Submit Construction Plan Status Report in accordance with Section 5.3.2 of this Agreement	Approved Project Sponsor	July 14, 2029** October 12, 2029**
14	Submit a Participating TO application for the Project to the CAISO in accordance with Section 4.3.1.1 of the CAISO Tariff	Approved Project Sponsor	December 17, 2029**
15	Execute agreement with applicable Interconnecting PTO prior to commencement of construction	Approved Project Sponsor	December 21, 2029**
16	Submit Construction Plan Status Report in accordance with Section 5.3.2 of this Agreement	Approved Project Sponsor	January 10, 2030** April 10, 2030** July 9, 2030**
17	Commence Construction	Approved Project Sponsor	July 15, 2030**
18	Submit Construction Plan Status Report in accordance with Section 5.3.2 of this Agreement	Approved Project Sponsor	October 7, 2030** January 5, 2031** May 9, 2031**
19	Submit final Project specifications in accordance with Section 5.4.2 of this Agreement	Approved Project Sponsor	90 Days prior to testing commencement**

20	**Provide comments on final Project specifications in accordance with Section 5.4.2 of this Agreement**	**CAISO**	**Response within 30 CD of request****
21	**Submit Construction Plan Status Report in accordance with Section 5.3.2 of this Agreement**	**Approved Project Sponsor**	**July 4, 2031** October 2, 2031****
22	**Commence Testing**	**Approved Project Sponsor**	**November 15, 2031****
23	**Energization Date**	**Approved Project Sponsor**	**December 31, 2031****
24	**Submit Construction Plan Status Report in accordance with Section 5.3.2 of this Agreement**	**Approved Project Sponsor**	**December 31, 2031****
25	**Complete Construction**	**Approved Project Sponsor**	**March 30, 2032****
26	**Complete procurement including material and resources**	**Approved Project Sponsor**	**March 30, 2032****
27	**CAISO Required In Service Date**	**Approved Project Sponsor**	**June 1, 2032***
28	**In accordance with Section 5.6.2 provide final "as-built" drawings, information and other documents**	**Approved Project Sponsor**	**120 days after Energization Date**
29	**In accordance with Section 5.6.1 provide final costs of the Project**	**Approved Project Sponsor**	**1 year after Energization Date**

1/ Dates in this Appendix B are good faith estimates and can be modified as follows:

* Change in milestone date requires an amendment to this Agreement pursuant to Section 25.10.

** Change in milestone date can be agreed to in writing by the representatives listed in Appendix D to this Agreement without further regulatory approval.

Appendix C

Security Arrangements Details

Infrastructure security of CAISO Controlled Grid equipment and operations and control hardware and software is essential to ensure day-to-day CAISO Controlled Grid reliability and operational security. FERC will expect the CAISO, and Approved Project Sponsor interconnected to the CAISO Controlled Grid to comply with Applicable Reliability Criteria. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

The Approved Project Sponsor shall meet the requirements for security implemented pursuant to the CAISO Tariff, including the CAISO's standards for information security posted on the CAISO's internet web site at the following internet address: http://www.caiso.com/pubinfo/info-security/index.html.

Appendix D

Addresses for Delivery of Notices and Billings

Notices:

Approved Project Sponsor:

Jacquelyn Blakley
Executive Director
Horizon West Transmission, LLC
1 California St. San Francisco CA 94111

With a copy to:
Fred Bauermeister
Project Director
Horizon West Transmission, LLC
1 California St. San Francisco CA 94111

Paul Mallmann
Project Manager
Horizon West Transmission, LLC
1 California St. San Francisco CA 94111

Email:
Jacquelyn.Blakley@nexteraenergy.com
Fred.Bauermeister@nexteraenergy.com
Paul.Mallmann@nexteraenergy.com

CAISO:

California ISO
Attn: Infrastructure Contracts & Management
250 Outcropping Way
Folsom, CA 95630
RegulatoryContracts@caiso.com

Alternative Forms of Delivery of Notices (telephone, facsimile or e-mail):

Approved Project Sponsor:

Jaime Hoffman
Horizon West Transmission, LLC
1 California St. San Francisco CA 94111
Jaime.hoffman@nexteraenergy.com

CAISO:

Deb Le Vine
dlevine@caiso.com
(916) 351-2144

RegulatoryContracts@caiso.com

Appendix E

Approved Project Sponsor's Costs of Project and Financial Obligations

The estimated cost components for the Project are as follows:

Transmission Line Costs	
Project Management	[redacted]
Site Evaluation	[redacted]
Regulatory Permitting	[redacted]
Land Acquisition	[redacted]
Engineering & Surveying	[redacted]
Material	[redacted]
Construction Labor	[redacted]
Surveying, Geotechnical Studies, Engineering, and Permitting	[redacted]
Testing, Commissioning, Energization	[redacted]
Administrative & General Overhead	[redacted]
Miscellaneous & Other Expenses	[redacted]
Total	[redacted]

Approved Project Sponsor may adjust the amounts in each cost category as needed during the term of this Agreement provided the total Project cost has a soft cap of $256,000,000. [redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

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[redacted]

- [redacted]

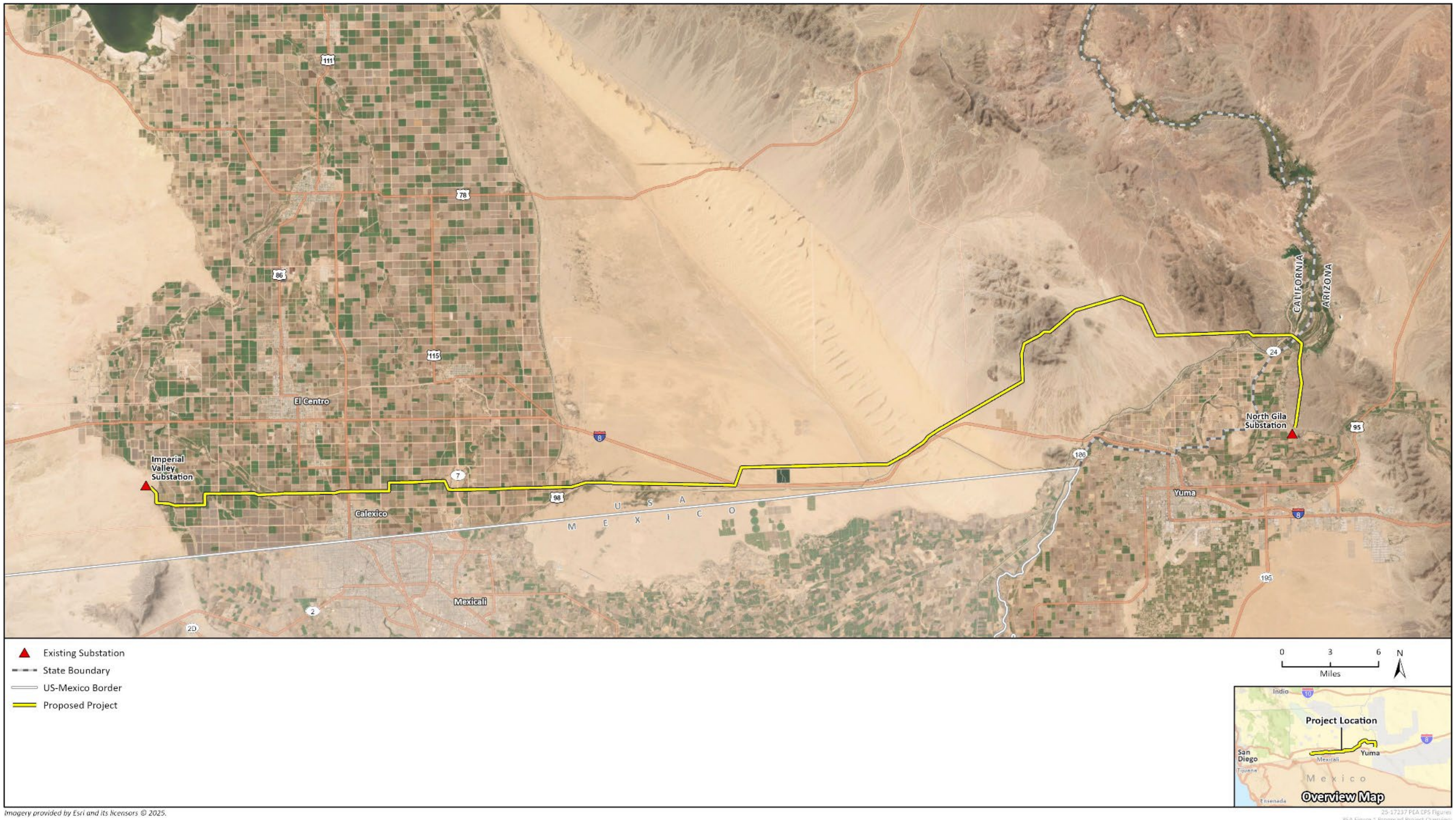
[redacted]

In accordance with Section 5.6.1, the Approved Project Sponsor shall provide a summary of the final cost of the construction of the Project as soon as reasonably practicable within twelve (12) months of the completion of construction.

EXHIBIT 5

PROJECT MAP

Exhibit 5
Map of the Project



PEA Figure 3-1 Proposed Project Overview Map

EXHIBIT 6

PROJECT COST ESTIMATE

(PUBLIC VERSION)

Exhibit 6 (PUBLIC)
Project Cost Estimate

<u>Construction Cost Estimate and Cost Containment Measures</u>

As noted in the CAISO Board-approved 2022-2023 Transmission Plan, the CAISO estimated the cost to construct the Ironwood Project as approximately $340 million.[1] [redacted]

Transmission Line Costs	
Project Management	[redacted]
Site Evaluation	[redacted]
Regulatory Permitting	[redacted]
Land Acquisition	[redacted]
Engineering & Surveying	[redacted]
Material	[redacted]
Construction Labor	[redacted]
Surveying, Geotechnical Studies, Engineering & Permitting	[redacted]
Testing, Commissioning, Energization	[redacted]
Administrative & General Overhead	[redacted]
Miscellaneous & Other Expenses	[redacted]
TOTAL	[redacted]

Appendix E of the APSA (provided in Exhibits 4 and 4C (Confidential Version) provides that Horizon West may adjust the amounts in each cost category as needed during the term of the APSA provided the total project cost has a soft cap of $256,000,000.

<u>Operating Cost Estimate</u>

Horizon West estimates that its forecasted operations and maintenance costs ("O&M"), inclusive of administrative and general costs ("A&G"), beginning in the year following COD total approximately [redacted]

[1] *See* 2022-2023 Transmission Plan, attached to Horizon West's CPCN Application as <u>Exhibit 1</u>.

Dismantling Cost Estimate

Separately, the estimated costs for dismantling the Ironwood Project at the end of its useful life (estimated to be 2098) are as follows:

Transmission Line Costs	Cost Estimate
Company Supplied Materials	[redacted]
Engineering, Procurement, & Construction Contractor	[redacted]
Engineering & Overhead	[redacted]
Escalation (at [redacted] per year until 2098)	[redacted]
Contingency ([redacted] total)	[redacted]
TOTAL	[redacted]

EXHIBIT 7

PROJECT IMPLEMENTATION PLAN

Exhibit 7

Project Implementation Plan

1.0 INTRODUCTION

Horizon West Transmission, LLC ("Horizon West") provides this Project Implementation Plan ("Plan") in support of Horizon West's Application for a Certificate of Public Convenience and Necessity ("Application") for the Ironwood Transmission Line Project ("Ironwood Project") pursuant to California Public Utilities ("PU") Code Section 1003(b). This Plan demonstrates how the Ironwood Project will be scoped, budgeted, designed, contracted, procured, and constructed. The Plan also shows how all major tasks will be integrated and includes a timetable identifying the permitting, land, interconnection, design, procurement, construction, commissioning, and operation dates for each major component of the Ironwood Project.

2.0 PROJECT SCOPE

The Proposed Project is an approximately 86-mile-long 500 kilovolt ("kV") transmission line from Arizona Public Service Company's ("APS") North Gila Substation to San Diego Gas & Electric Company's ("SDG&E") Imperial Valley Substation. The Proposed Project would be located in western Yuma County, Arizona and Imperial County, California, crossing predominantly unincorporated lands and in the vicinity of the incorporated communities of El Centro, Imperial, Calexico, Holtville, and Brawley, California; and Yuma, Arizona, and lands of the United States. The Proposed Project is intended to mitigate resource deliverability constraints as identified in the CAISO's 2022-2023 Transmission Plan to enable delivery of renewable generation in the resource portfolios approved by the California Public Utilities Commission ("Commission" or CPUC").

The Proposed Project will include construction and operation of the overhead transmission line, up to the point of change in ownership ("POCO") within approximately 100 feet of the connecting utilities' substation property lines. At each substation, the owning utility would install the 500 kV transmission line from the respective POCO and line shunt reactors to a new 500 kV bus within the substation to enable interconnection of the Proposed Project. Horizon West plans to integrate a combination of self-supporting lattice towers, guyed "v" lattice towers and self-supported tubular steel monopoles as the main structures for the project with an average span of 1,600 feet and average height of 150 feet. The conductor wires will be 715.5 kcmil 30/19 Redwing ACSS configured in a triple bundle per phase, totaling nine conductors across the three phases. Additionally, for lightning protection, Horizon West will install two ground wires: one overhead ground wire ("OHGW") and one Optical Ground Wire ("OPGW"), which also adds communication capabilities to the project.

The project site will have a Right of Way ("ROW") of 250 feet across the route. Approximately 70% is desert terrain mostly managed by Bureau of Land Management ("BLM") and 30% in privately owned agricultural field. Permanent easement rights would be acquired by Horizon West through negotiations with private landowners. New permanent or modified ROWs or easements may also be acquired from the applicable public agency through that agency's designated process. The total number of land rights to be acquired would be finalized following the Commission's approval of the proposed Ironwood Project's route and during final engineering. Pursuant to California Public Utilities ("PU") Code section 612, as a public utility, Horizon West has the power of eminent domain to acquire any necessary land rights for construction of the Proposed Project within California.

3.0 OBJECTIVE AND GOALS

During the execution phase—which includes final engineering, procurement, and construction—Horizon West's objectives and goals will consist of:

- Meet the CAISO's policy-driven need for the Ironwood Project to support mitigation of the East of Miguel deliverability constraint,[1] which the CAISO found presently results in zero deliverability for resources in the Commission's base portfolio (3,080 MW) and sensitivity portfolio (10,398 MW) of renewable resources (CAISO 2022-2023 Transmission Plan).

- As part of the Southern Area Reinforcement, support the cost-effective, common upgrade mitigation of identified transmission constraints on the Devers-Red Bluff 500 kV, East of Miguel, Bay Boulevard-Silvergate, Encina-San Luis Rey, Sycamore area, San Luis Rey-San Onofre, and Silvergate-Old Town lines.

- Meet the CAISO's functional specifications for the Ironwood Project as set forth in Appendix I of the 2022-2023 Transmission Plan.

- Achieve commercial operation by December 2030 to provide critical deliverability access to generation resources in California, Arizona, and New Mexico.

- Design, construct, and operate the Ironwood Project to minimize potential wildfire and other hazards, with public safety and well-being as a top priority, consistent with Horizon West's approved Wildfire Mitigation Plan.

- Meet the need for the Ironwood Project in a safe, cost-effective manner consistent with Horizon West's Approved Project Sponsor Agreement to minimize cost impacts to customers.

- Minimize disturbance to local communities by siting the project adjacent to existing utilities, avoiding residential areas as much as possible.

- Avoid, minimize, or mitigate potential impacts to sensitive environmental resources and areas.

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[1] As described in CAISO's 2022-2023 Transmission Plan, deliverability of portfolio resources east of the existing SDG&E Miguel Substation is limited by thermal overloading of existing lines and transformers (referred to as the "East of Miguel Constraint").

- Design, construct, and operate the project in conformance with Horizon West's standards, the National Electric Safety Code, and other applicable federal and state codes and regulations.

4.0 PROJECT IMPLEMENTATION PLAN

4.1 Introduction

Horizon West, with support of its parent company NextEra Energy, Inc.'s ("NextEra") shared services employees in the Engineering and Construction ("E&C") and Integrated Supply Chain ("ISC") departments (subject to the Commission granting the waivers requested by Horizon West from certain of the affiliate transaction rules applicable to energy utilities as outlined in Horizon West's Application), will manage the engineering, procurement, and construction activities for the Ironwood Project. Due to the extensive engineering design required and long lead time for equipment procurement and testing, engineering and procurement activities will begin prior to regulatory approval, which is requested by March 2029. Construction cannot begin until after regulatory approval. Any required permits identified in the regulatory approval process must also be obtained before construction can begin. Horizon West's Land Services team will manage acquisition of land rights including permanent easements to facilitate construction, operation and maintenance of the Ironwood Project in addition to temporary access rights and material laydown yards to facilitate its construction.

4.2 Project Management Team

Horizon West's Project Manager has the overall responsibility for the successful completion of the Ironwood Transmission Line Project within the approved budget and on schedule. Responsibilities include: safety, planning, obtaining regulatory approvals, managing the approved budget, scheduling, execution (detailed engineering, procurement, land acquisition, construction, and commissioning), and the overall quality of the project. Project work will be executed by a cross-functional team of experienced employees of NextEra affiliates. The Project Management Team ("PMT") is responsible for the successful implementation of the Ironwood Transmission Line Project. Key members of the project team include a Project Engineer, a Project Controls Lead (cost and schedule responsibilities), a Procurement and Contracting Lead, a Safety Manager, a Land Services Lead and an Environmental Compliance Lead and report to the Project Manager.

The PMT is responsible for tracking costs, scope changes, schedules, and construction performance. The PMT will have regular meetings to discuss project status, review performance, and identify any special needs or significant concerns. Horizon West will execute the Ironwood Transmission Line Project using the same proven project management principles that it and other NextEra subsidiaries have successfully employed for other on-time and under-budget projects. Horizon West's approach will consist of active management of all aspects of the Ironwood Transmission Line Project by an experienced and highly skilled project team of professionals and Subject Matter Experts ("SME"). The PMT will take responsibility and ensure accountability for all phases of the Ironwood Transmission Line Project's execution.

Listed below are the project management process steps and actions Horizon West will take during its development and construction of the Ironwood Transmission Line Project:

i. Project Launch and Scoping
ii. Master Project Schedule
iii. Risk Identification and Mitigation
iv. Comprehensive Project Cost Estimate/Budget
v. Monitor and Control Project Costs
vi. Track and Report on Project Performance

4.3 Project Launch and Scoping

The first step in managing project execution and risk is a thorough collection, understanding, and documentation of the project scope. This scope includes the CAISO functional and project specific specifications, milestones, and necessary approvals and permits.

To facilitate the exchange of project information and communication by team members, a Unifier (Oracle's project management software) site has been established for the Ironwood Transmission Line Project. This secure Unifier site is accessible by all internal and external team members. Throughout project execution, the site will be used as the definitive source of project information. The project dashboard, and other pertinent project documents and information reside on the site, providing instant access to team members who rely on accurate and up-to-date project information.

Horizon West has assembled a team of accomplished professionals and SMEs to make up the PMT. This team will draw upon NextEra's shared resources and contractors for the project execution. Monthly PMT meetings will occur throughout the project's life.

4.3.1 Master Project Schedule

The Horizon West Project Controls Manager assigned a schedule and cost engineer to the project. Horizon West will integrate schedules from all consultants, suppliers, contractors, and other participating entities into the master schedule. With support of its engineers, contractors, and environmental consultants, Horizon West will coordinate and conduct focused workshops to detail all permitting, pre-construction compliance tasks, environmental restrictions, construction clearance limitations, engineering, procurement, and construction activities, as well as their dependencies. This includes coordination and scheduling with SDG&E, APS and the CAISO. As part of the schedule development, Horizon West conducts regular reviews to verify and confirm the schedule tasks and logic. Horizon West will schedule and track all phases of the project with the Primavera software.

Bi-weekly schedule meetings with all participants are held throughout the development and construction of the Ironwood Transmission Line Project to update the schedule, review the two-week and four-week look ahead, and address critical path items. Any slip in the schedule will require the participating engineer, consultant, or contractor to develop a mitigation plan to get back on schedule.

When schedule and variances are identified, the Horizon West PMT will request a recovery plan from the project contractor causing the variance. The recovery plan will explain the root cause of the variance as well as mitigation to recover the baseline schedule. The Horizon West PMT will evaluate the recovery plan for impacts to dependent activities with consideration to available project float.

4.3.2 Identification of Risks and Mitigation Plan

Horizon West has developed a risk and mitigation matrix to identify and address project risks and issues associated with varying conditions. The Risk Matrix contains an assessment of the risks and issues, estimated risk exposure, potential impact on schedule, cost or scope, as well as potential options mitigating or eliminating the risk or issue. During project execution, the PMT meets on a monthly basis specifically to address each item currently on the risk and mitigation matrix and to consider adding any additional items that have been revealed. Throughout project execution, the Risk Matrix is used to manage allocated and unallocated contingency to support forecasting of final project cost.

4.3.3 Comprehensive Project Cost Management and Tracking

For tracking of the Ironwood Transmission Line Project budget, Horizon West has set up the project in its Work Breakdown Structure ("WBS") accounting system. The WBS system enables Horizon West to track internal, supplier, and contractor costs and time spent on the Ironwood Transmission Line Project.

Much like the master project schedule, a comprehensive project budget estimate is crucial to planning and tracking project expenses. This budget estimate is a build-up of estimated project costs based on the project scope. During the project execution phase, the Ironwood Transmission Line Project cost estimate/budget is tracked through NextEra's WBS, and projected costs will be updated based on actual executed contract values and expenditures.

A component of the Ironwood Transmission Line Project budget is the contingency assessed to the Ironwood Transmission Line Project. The contingency is based on the project risks identified. Based on its review, Horizon West has assigned a probability of occurrence and a cost to major risk items and applied a weighted formula to develop the cost contingencies for this project.

4.3.4 Monitor and Control Project Schedule, Cost, and Risks

Throughout the project execution phase, the schedule, budget, and risk logs for the Ironwood Transmission Line Project will be updated and optimized based on current information. The Project Manager will use the WBS cost and time account data, in conjunction with the man-hour forecasts provided in the budget and schedule to forecast project resource requirements.

During the project execution phase, the Project Manager will hold a weekly lead team meeting. The meeting is used to update the PMT on project status and plans.

4.3.5 Track and Reporting on Project Performance

During the project execution phase, the PMT will track project progress, prepare project status reports, and forecast future project resource requirements. To accomplish this, the team utilizes the WBS cost and time accounting system, budget, and schedule. As with other NextEra projects, the team will produce a project dashboard for the Ironwood Transmission Line Project to provide an up-to-date status of pertinent project metrics. Team members and senior management have a quick and easy tool to access a project's health by viewing the dashboard.

Finally, the Project Manager will hold monthly senior management project status update meetings to review project progress and to make timely decisions to ensure project success.

4.4 Procurement Process

On the Ironwood Transmission Line Project, Horizon West has competitively bid and hired S&L Engineers, LTD as its Engineer of Record ("EOR"). The EOR reports to Horizon West's Project Engineer. The EOR is responsible for preliminary and detailed engineering design to support, permitting, procurement, bid preparation, and evaluation, and the development of material and installation specifications.

The EOR in conjunction with the Horizon West Project Manager, Project Engineer, ISC lead, and SMEs developed the detailed Transmission Line contract, scope of work documents and specifications.

Horizon West will directly procure all major material such as structures, conductor cable, OPGW, OHGW, insulators and hardware. ISC team has requested proposals, received pricing from different vendors, and will request best and final offers months before order needs to be placed according to the Project's schedule. All other required materials for construction are included in the Transmission Line construction contractor.

Horizon West will competitively bid and contracted PAR Western Line Contractors, LLC ("PAR West") for the construction as the Transmission Line contractor. PAR West will support constructability assessment during the design and permitting phase, in addition to being responsible for the construction and installation of the Ironwood Transmission Line Project.

4.5 Project Construction Management Plan

Horizon West's construction management approach will utilize a mixture of experienced NextEra in-house resources and qualified contractors. Horizon West approach to project execution will consist of three contract packages:

- EOR services contract (Complete);
- Transmission Line Construction contract (Complete); and

- Equipment supply contracts (first purchase order expected to be placed January 2027).

Horizon West project and construction management personnel will review and monitor all contractor work and progress regularly. Table A-1, Project Schedule, identifies the preliminary design, construction, completion, and operational dates for each of the major project components.

5.0 COST ESTIMATE

The cost estimate required by PU Code Section 1003(c) is found in Section IV.E. of the Application and Exhibit 6 to the Application.

6.0 COST CONTROL PLAN

A Project Controls Lead has been assigned to the Ironwood Transmission Line Project to manage cost and schedule. The Project Controls Lead is responsible to:

- Develop a WBS structure for the project;
- Align detailed project estimate with WBS structure for tracking;
- Monitor and update schedule;
- Monitor and assist with invoice processing;
- Monitor and report on cost and general health of the project;
- Assist in identification and tracking of project risks using the project risk matrix;
- Monitor staffing levels (both internal and external);
- Monitor material deliveries and any impacts on schedule; and
- Maintain and monitor cash flow and spend curves.

Multiple contracts will be required during the execution phase of the Ironwood Transmission Line Project. These include the EOR, Construction, equipment contracts.

The EOR Services Contract is a fixed price, not-to-exceed contract and includes a deliverables schedule. Progress payments will be made against each task estimate based on actual work and deliverables completed to date.

Construction contract is a fixed price based on a clearly defined scope of work. The deliverables and the measure of performance and progress against the WBS will serve as the basis for progress payments made to the contractor. The contractors will submit invoices for Horizon West's review and approval, along with all required supporting documentation, for all work performed during the billing period. These contracts may only be changed by a Contract Change Order ("CCO") approved by the Project Manager based on adjustments in project scope.

The Horizon West PMT reports the overall health of the project monthly to the executive management team. This review includes scope, staffing, capital costs, schedule, environmental and safety issues, execution progress, and risk management/contingency allocation.

Table A-1, Project Schedule

Activity ID	Activity Name	At Completion Duration	Start	Finish
Ironwood 500kV Transmission Line Project Schedule		1655	03-Jun-24 A	16-Dec-30
Milestones		1011	22-Dec-26	16-Dec-30
Develop Contracts for Project Work		15	02-Oct-25	22-Oct-25
Permitting		1029	12-May-25 A	07-Jun-29
Transmission ROW Acquisition (Land and Right of Way)		1148	17-Dec-24 A	03-Jul-29
Engineering and Design		1239	03-Jun-24 A	27-Apr-29
Transmission Equipment Procurement		810	09-Feb-27	19-Apr-30
Construction		410	23-Apr-29	30-Nov-30
UCA	Unrestricted Construction Access	0	27-Jun-29	
Incumbent PTO		120	28-Apr-29	18-Sep-29
Transmission Construction		385	23-Apr-29	25-Oct-30
Outage / tie-in Window		435	27-Jun-29	30-Nov-30
Agreements		1559	15-Oct-24 A	13-Dec-30
Pre- Operation Testing and Commissioning		172	17-Apr-30	13-Dec-30
In-Service Date (ISD)		0	13-Dec-30	13-Dec-30

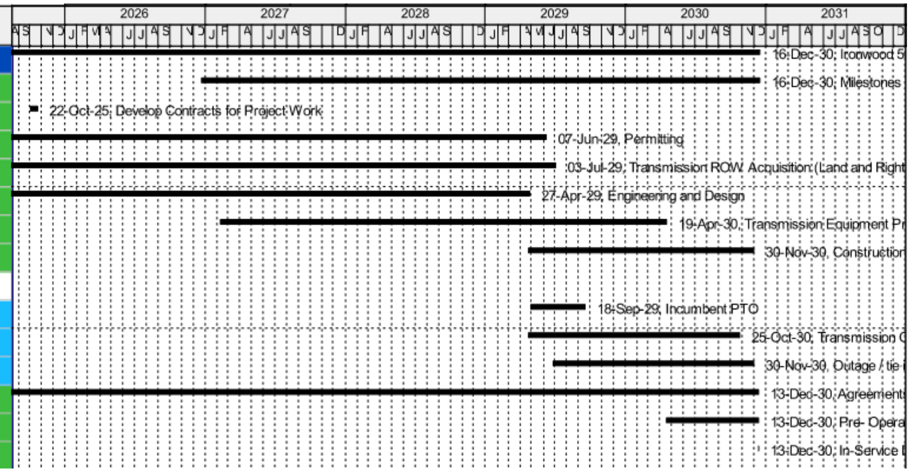


EXHIBIT 8

HORIZON WEST FINANCIAL STATEMENT

Horizon West Transmission, LLC
Balance Sheet

	06/24 Q	09/24 Q	12/24 Q	03/25 Q	06/25 Q
Date Ended	6/30/2024	9/30/2024	12/31/2024	3/31/2025	6/30/2025
Utility Plant ($000)					
Utility Plant	77,077	77,078	77,078	77,767	77,985
Construction Work in Progress	15,752	17,373	20,371	23,188	26,645
Total Utility Plant	92,829	94,452	97,449	100,955	104,631
Less: Accum Provision for Depr, Amort, & Depl	4,933	5,490	6,046	6,603	7,169
Net Utility Plant (excluding Nuclear Fuel)	87,896	88,962	91,403	94,352	97,462
Nuclear Fuel	0	0	0	0	0
Less: Accum Prov for Amort of Nuclear Assembly	0	0	0	0	0
Nuclear Fuel - Net	0	0	0	0	0
Net Utility Plant Including Nuclear Fuel	87,896	88,962	91,403	94,352	97,462
Other Property and Investments ($000)					
Non Utility Property	0	0	0	0	0
Less: Accum Provision for Nonutility Depreciation	0	0	0	0	0
Investment In Associated Companies	0	0	0	0	0
Investment In Subsidiary Companies	0	0	0	0	0
Noncurrent Portion of Allowances	0	0	0	0	0
Other Investments	0	0	0	0	0
Special Funds	0	0	0	0	0
LT Portion of Deriv Assets	0	0	0	0	0
LT Portion of Hedge Deriv Assets	0	0	0	0	0
Total Other Property and Investments	0	0	0	0	0
Current and Accrued Assets ($000)					
Cash	8,289	18,031	7,770	7,837	4,549
Special Deposits	0	0	0	0	0
Working Funds	0	0	0	0	0
Temporary Cash Investment	0	0	0	0	0
Notes Receivable	0	0	0	0	0
Customer Accounts Receivable	12,190	9,744	9,126	2,211	2,836
Other Accounts Receivable	13	3	3	6	5
Less: Accumulated Provision for Uncollectibles	0	0	0	0	0
Accounts Receivable from Associated Companies	384	232	34	571	375
Notes Receivable From Associated Companies	0	0	0	0	0
Interest and Dividends Receivable	0	0	0	0	0
Rents Receivable	0	0	0	0	0
Fuel Stock	0	0	0	0	0
Fuel Stock Expense Undistributed	0	0	0	0	0
Residuals (electric) & Extracted Products (gas)	0	0	0	0	0
Plant Materials and Operating Supplies	0	0	0	0	0
Merchandise	0	0	0	0	0
Other Material and Supplies	0	0	0	0	0
Nuclear Materials Held for Sale	0	0	0	0	0
Accrued Utility Revenue	0	0	0	0	0
Allowances	0	0	0	0	0
Noncurrent Portion of Allowances	0	0	0	0	0
Stores Expense Undistributed	0	0	0	0	0
Gas Stored Underground - Current	0	0	0	0	0
Liquefied Natural Gas Held for Processing	0	0	0	0	0
Prepayments	145	140	98	612	304
Advances for Gas Explor, Development & Production	0	0	0	0	0
Miscellaneous Current and Accrued Assets	0	0	0	0	0
Derivative Assets Other than Hedges	0	0	0	0	0
Less: LT Portion of Deriv Assets	0	0	0	0	0
Derivative Assets: Hedges	0	0	0	0	0
Less: LT of Hedge Deriv Assets	0	0	0	0	0
Total Current and Accrued Assets	21,021	28,150	17,031	11,238	8,068
Deferred Debits ($000)					
Unamortized Debt Expense	0	0	0	0	0
Extraordinary Property Losses	0	0	0	0	0
Unrecovered Plant & Regulatory Study Costs	0	0	0	0	0

Other Regulatory Assets	20,284	17,208	14,134	14,555	14,425
Preliminary Survey & Investigation Charges	0	0	0	0	0
Prelim Survey & Investigation (gas)	0	0	0	0	0
Other Preliminary Survey	0	0	0	0	0
Clearing Accounts	0	0	0	0	0
Temporary Facilities	0	0	0	0	0
Miscellaneous Deferred Debits	0	0	0	0	0
Deferred Losses From Disposition of Utility Plant	0	0	0	0	0
Research & Development Expenditures	0	0	0	0	0
Unamortized Loss on Reacquired Debt	0	0	0	0	0
Accumulated Deferred Income Taxes - Asset	3,227	3,758	3,389	3,155	2,858
Unrecovered Purchased Gas Costs	0	0	0	0	0
Total Deferred Debits	23,512	20,966	17,523	17,710	17,283
Total Assets and Other Debits	132,428	138,079	125,958	123,300	122,813
Capital & Long Term Debt ($000)					
Common Stock Issued	0	0	0	0	0
Preferred Stock Issued	0	0	0	0	0
Capital Stock Subscribed	0	0	0	0	0
Stock Liability for Conversion	0	0	0	0	0
Premium on Capital Stock	0	0	0	0	0
Other Paid In Capital	38,340	38,300	29,654	25,470	23,967
Installments Received on Capital Stock	0	0	0	0	0
Less: Discount on Capital Stock	0	0	0	0	0
Less: Capital Stock Expense	0	0	0	0	0
Retained Earnings	23,849	24,900	25,735	26,989	28,497
Unappropriated Undistributed Subsidiary Earnings	0	0	0	0	0
Less: Reacquired Capital Stock	0	0	0	0	0
Accumulated Other Comprehensive Income	0	0	0	0	0
Total Proprietary Capital	62,189	63,200	55,389	52,460	52,465
Bonds	0	0	0	0	0
Less: Reacquired Bonds	0	0	0	0	0
Advances From Associated Companies	41,517	41,557	36,203	34,387	39,290
Other Long-term Debt	0	0	0	0	0
Unamortized Premium on Long-term Debt	0	0	0	0	0
Less: Unamortized Discount on LTD: Dr	0	0	0	0	0
Total Long-term Debt	41,517	41,557	36,203	34,387	39,290
Total Capitalization, at Book Value	103,706	104,757	91,592	86,847	91,755
Other Noncurrent Liabilities ($000)					
Obligations Under Capital Leases-Noncurrent	0	0	0	0	0
Accumulated Provision for Property Insurance	0	0	0	0	0
Accumulated Provision for Injuries & Damages	0	0	0	0	0
Accumulated Provision for Pensions & Benefits	0	0	0	0	0
Accumulated Miscellaneous Operating Provisions	0	0	0	0	0
Accumulated Provision for Rate Refunds	0	0	0	0	0
Asset Retirement Obligations	0	0	0	0	0
LT Portion of Deriv Liabilities	0	0	0	0	0
LT Portion of Hedge Deriv Liab	0	0	0	0	0
Total Other Noncurrent Liabilities	0	0	0	0	0
Current and Accrued Liabilities ($000)					
Notes Payable	0	0	0	0	0
Accounts Payable	156	517	365	543	459
Notes Payable to Associated Companies	0	0	0	0	0
Accounts Payable to Associated Companies	2,021	1,500	3,486	5,811	1,305
Customer Deposits	0	0	0	0	0
Taxes Accrued	5,655	7,713	7,037	7,067	7,295
Interest Accrued	0	0	0	0	0
Dividends Declared	0	0	0	0	0
Matured Long-term Debt	0	0	0	0	0
Tax Collections Payable	0	9	0	1	0
Miscellaneous Current and Accrued Liabilities	874	1,967	840	868	650
Obligations Under Capital Leases-Current	0	0	0	0	0
Derivative Liabilities Other than Hedges	0	0	0	0	0

Less: LT Portion of Deriv Liab	0	0	0	0	0
Derivative Liabilities: Hedges	0	0	0	0	0
Less: LT of Hedge Deriv Liab	0	0	0	0	0
Total Current and Accrued Liabilities	8,706	11,705	11,729	14,290	9,709
Deferred Credits ($000)					
Customer Advances for Construction	0	0	0	0	0
Accumulated Deferred Investment Tax Credits	0	0	0	0	0
Deferred Gains From Disposal of Utility Plant	0	0	0	0	0
Other Deferred Credits	0	0	1,139	1,139	1,139
Other Regulatory Liabilities	7,285	9,681	10,476	9,756	8,863
Unamortized Gain on Reacquired Debt	0	0	0	0	0
Accumulated Deferred Income Taxes - Liabilities	12,732	11,935	11,021	11,269	11,348
Total Deferred Credits	20,017	21,616	22,636	22,163	21,349
Total Liabilities and Other Credits	132,428	138,079	125,958	123,300	122,813

Horizon West Transmission, LLC
Income Statement

	06/24 Q	09/24 Q	12/24 Q	03/25 Q	06/25 Q	LTM
Date Ended	6/30/2024	9/30/2024	12/31/2024	3/31/2025	6/30/2025	6/30/2025
Operating Revenues ($000)						
Electric Sales for Resale	0	0	0	0	0	0
Operating Revenue: Electric	8,271	8,787	9,784	5,358	5,649	29,578
Operating Revenue: Other	0	0	0	0	0	0
Operating Revenue: Total	8,271	8,787	9,784	5,358	5,649	29,578
Operating Expenses ($000)						
Operating Expense - Electric	3,096	3,041	3,781	3,418	2,920	13,160
Other Operating Expense	0	0	0	0	0	0
Operating Expense: Total	3,096	3,041	3,781	3,418	2,920	13,160
Maintenance Expense: Electric	20	(32)	0	107	82	157
Maintenance Expense: Other	0	0	0	0	0	0
Maintenance Expense: Total	20	(32)	0	107	82	157
						0
Operating Revenue: Total	8,271	8,787	9,784	5,358	5,649	29,578
Operating Expense: Total	3,096	3,041	3,781	3,418	2,920	13,160
Maintenance Expense: Total	20	(32)	0	107	82	157
Taxes Other Than Inc Taxes: Total	319	304	325	315	314	1,258
Utility EBITDA: Total	4,836	5,474	5,678	1,518	2,333	15,003
Operating Income ($000)						
Depreciation Expense: Total	500	500	499	501	511	2,011
Depr Exp for Asset Ret Costs: Total	0	0	0	0	0	0
Amort & Depl of Utility Plant: Total	56	57	57	57	59	230
Amort of Utility Plant Acquisition Adj: Total	0	0	0	0	0	0
Amortization of Property Losses: Total	0	0	0	0	0	0
Amortization of Conversion Expense: Total	0	0	0	0	0	0
Operating Depreciation & Amortization	556	557	556	558	570	2,241
Regulator Debits: Total	2,855	2,903	2,903	0	0	5,806
Regulator Credits: Total	0	0	0	1,228	580	1,808
Taxes Other Than Inc Taxes: Total	319	304	325	315	314	1,258
Operating Income Taxes, Federal	1,200	1,225	1,437	62	165	2,889
Operating Income Taxes, Other	575	587	(272)	42	91	448
Federal & Other Income Taxes: Total	1,775	1,812	1,165	104	256	3,337
Provision for Def Inc Taxes - Total	374	2,453	1,621	683	591	5,348
Provision for Def Inc Taxes -Cr - Total	1,865	3,856	2,278	283	300	6,717
Investment Tax Credit Adj-net - Total	0	0	0	0	0	0
Gains From Disp of Utility Plant - Total	0	0	0	0	0	0
Losses From Disp of Utility Plant - Total	0	0	0	0	0	0
Gains From Disp of Allowances - Total	0	0	0	0	0	0
Losses From Disp of Allowances - Total	0	0	0	0	0	0
Accretion Expense: Total	0	0	0	0	0	0
Total Utility Operating Expense - Total	7,130	7,183	8,073	3,673	3,854	22,783
Net Utility Operating Income - Total	1,140	1,604	1,711	1,685	1,794	6,794
Other Income and Deductions ($000)						
Revs. From Merchandising, Jobbing, & Contracting	0	0	0	0	0	0
Costs & Exp-Merchandising, Jobbing, & Contracting	0	0	0	0	0	0
Revenue From Nonutility Operations	0	0	0	0	0	0
Expense of Nonutility Operations	0	0	0	0	0	0
Nonoperating Rental Income	0	0	0	0	0	0
Equity In Earnings of Subsidiary Companies	0	0	0	0	0	0
Interest and Dividend Income	135	250	349	63	26	688
Allowance for Funds Used During Construction	229	235	239	247	255	976
Miscellaneous Nonoperating Income	0	0	0	0	0	0
Gain on Disposition of Property	0	0	0	0	0	0
Total Other Income	365	483	589	310	281	1,663
Loss on Disposition of Property	0	0	0	0	0	0
Miscellaneous Amortization	0	0	0	0	0	0
Donations	0	0	0	0	0	0
Life Insurance	0	0	0	0	0	0
Penalties	0	0	0	0	0	0
Expenditure-Political Activities	0	0	18	4	18	40
Other Deductions	656	512	1,203	342	113	2,170
Miscellaneous Income Deductions	656	512	1,221	346	131	2,210
Total Other Income Deductions	656	512	1,221	346	131	2,210
Taxes Other Than Income Taxes	0	0	0	0	0	0
Other Income Taxes - Federal	(100)	(66)	(137)	(52)	(18)	(273)
Other Income Taxes - Non-Federal	(46)	(31)	(110)	(24)	(8)	(173)

Provision for Deferred Income Taxes	0	0	42	0	0	42
Provision for Deferred Income Taxes - credit	0	0	9	0	0	9
Investment Tax Credit Adjustment - net	0	0	0	0	0	0
Investment Tax Credits	0	0	0	0	0	0
Total Taxes on Other Income & Deductions	(146)	(97)	(213)	(75)	(27)	(412)
Net Other Income and Deductions	(145)	68	(419)	39	178	(134)
Interest Charges ($000)						
Interest on Long-Term Debt	0	0	0	0	0	0
Amortization of Debt Discount and Expenses	0	0	0	0	0	0
Amortization of Loss on Reacquired Debt	0	0	0	0	0	0
Amortization of Premium on Debt - credit	0	0	0	0	0	0
Amortization of Gain on Reacquired Debt - credit	0	0	0	0	0	0
Interest on Debt to Associated Companies	485	455	455	404	424	1,738
Other Interest Expense	59	231	69	145	121	566
Allowance on Borrowed Funds Used During Const-cr	64	65	67	78	81	291
Net Interest Charges	480	621	457	471	463	2,012
Net Income before Extraordinary Items	515	1,051	835	1,254	1,508	4,648
Extraordinary Items ($000)						
Extraordinary Income	0	0	0	0	0	0
Extraordinary Deductions	0	0	0	0	0	0
Net Extraordinary Items	0	0	0	0	0	0
Income Taxes: Federal and Other	0	0	0	0	0	0
Extraordinary Items after Taxes	0	0	0	0	0	0
Net Income	515	1,051	835	1,254	1,508	4,648

EXHIBIT 9

NEXTERA ENERGY, INC. PROXY STATEMENT

2025 NOTICE OF ANNUAL MEETING AND PROXY STATEMENT

YOUR VOTE IS IMPORTANT
PLEASE SUBMIT YOUR PROXY PROMPTLY

NextEra Energy is committed to meeting the nation's increasing energy demand with a diverse mix of energy while keeping bills as low as possible.

We encourage our shareholders to enroll in e-delivery:

Online at www.proxyvote.com/NEE

Scan the QR code

VOLUNTARY ELECTRONIC RECEIPT OF FUTURE PROXY MATERIALS

NextEra Energy is pleased to deliver proxy materials electronically via the internet. Electronic delivery allows NextEra Energy to provide you with the information you need for the annual meeting, while reducing environmental impacts and costs.

HOW TO VOTE

BY INTERNET

Go to the website www.proxyvote.com, 24 hours a day, seven days a week. You will need the control number that appears on your proxy card or on your Notice of Internet Availability of Proxy Materials (the "Notice").

BY TELEPHONE

Call 1-800-690-6903, 24 hours a day, seven days a week. You will need the control number that appears on your proxy card or Notice.

BY MAIL

If you received a full paper set of materials, date and sign your proxy card exactly as your name appears on your proxy card and mail it in the enclosed, postage-paid envelope. If you received the Notice, you may request a proxy card by following the instructions in your Notice. Even if you received a full paper set of materials, you may still vote by internet or telephone. You do not need to mail the proxy card if you are voting by internet or telephone.

IN PERSON

At the annual meeting.

NextEra Energy, Inc.
700 Universe Boulevard
Juno Beach, Florida 33408-0420

Notice of Annual Meeting of Shareholders

MAY 22, 2025

The 2025 Annual Meeting of Shareholders of NextEra Energy, Inc. ("NextEra Energy" or the "Company") will be held on Thursday, May 22, 2025, at 8:00 a.m., Central time, at 12 Sixth Street South, Minneapolis, Minnesota 55402 to consider and act upon the following matters:

MEETING AGENDA		BOARD RECOMMENDATION
1.	Election as directors of the nominees specified in the accompanying proxy statement	FOR each nominee
2.	Ratification of appointment of Deloitte & Touche LLP as NextEra Energy's independent registered public accounting firm for 2025	FOR
3.	Approval, by non-binding advisory vote, of NextEra Energy's compensation of its named executive officers as disclosed in the accompanying proxy statement	FOR
4.	Such other business as may properly be brought before the annual meeting or any adjournment(s) or postponement(s) of the annual meeting	

The proxy statement describes these matters thoroughly. NextEra Energy has not received notice of other matters that may properly be presented at the annual meeting.

The record date for shareholders entitled to notice of, and to vote at, the annual meeting and any adjournment(s) or postponement(s) of the annual meeting is March 25, 2025.

Admittance to the annual meeting will be limited to shareholders as of the record date or their duly appointed proxies. For the safety of attendees, all boxes, handbags and briefcases are subject to inspection. Cameras, cell phones, recording devices and other electronic devices are not permitted at the meeting.

NextEra Energy is pleased to deliver proxy materials electronically via the internet. Electronic delivery allows NextEra Energy to provide you with the information you need for the annual meeting, while reducing environmental impacts and costs.

REGARDLESS OF WHETHER YOU EXPECT TO ATTEND THE ANNUAL MEETING, PLEASE SUBMIT YOUR PROXY OR VOTING INSTRUCTIONS PROMPTLY SO THAT YOUR SHARES CAN BE VOTED.

By order of the Board of Directors,

DAVID FLECHNER
Vice President, Compliance & Corporate Secretary

Juno Beach, Florida
April 1, 2025

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE ANNUAL MEETING TO BE HELD ON MAY 22, 2025

This proxy statement and the NextEra Energy 2024 annual report to shareholders are available at www.proxyvote.com.

Table of Contents

Proxy Statement Summary

This summary highlights information contained elsewhere in this proxy statement. This summary does not contain all the information that you should consider. You should read the entire proxy statement carefully before voting. This proxy statement contains information related to the solicitation of proxies by the Board of Directors (the "Board") of NextEra Energy, Inc., a Florida corporation ("NextEra Energy," the "Company," "NEE," "we," "us" or "our"), in connection with the 2025 annual meeting of NextEra Energy's shareholders and at any adjournment(s) or postponement(s) of the meeting. On or about April 1, 2025, NextEra Energy began mailing this proxy statement and a Notice of Internet Availability of Proxy Materials to shareholders.

MEETING INFORMATION

TIME AND DATE	PLACE	RECORD DATE
8:00 a.m., Central time May 22, 2025	12 Sixth Street South, Minneapolis, Minnesota 55402	March 25, 2025
WEBCAST	**VOTING**	**ADMISSION**
The Company will provide a live audio webcast of the annual meeting from its website at http://www.nexteraenergy.com.	Shareholders as of the record date are entitled to vote. Each share of common stock, par value $.01 per share ("common stock"), is entitled to one vote for each director nominee and one vote for each of the other properly presented proposals to be voted.	An admission ticket is required to enter the annual meeting. See page 86 in the Questions and Answers About the Annual Meeting section regarding how to obtain a ticket.

VOTING MATTERS AND BOARD RECOMMENDATIONS

	PROPOSAL	BOARD VOTE RECOMMENDATION	PAGE REFERENCE
1.	Election of directors	FOR each nominee	8
2.	Ratification of appointment of Deloitte & Touche LLP as NextEra Energy's independent registered public accounting firm for 2025	FOR	20
3.	Advisory vote to approve NextEra Energy's compensation of its named executive officers	FOR	21

Business and Governance Highlights

~72 GW*
in operation

~12 GW
wind, solar and storage origination at NextEra Energy Resources, LLC (“NextEra Energy Resources” or “NEER”)

~16,800
employees

~$190 B
in total assets

HURRICANE RESTORATION
Florida Power & Light Company’s (“FPL”) smart grid technology avoided nearly 800,000 outages during Hurricanes Debby, Helene and Milton

~(6)%; ~8%
GAAP and adjusted earnings per share (“EPS”) growth compared to 2023

~25 GW
year-end backlog at NextEra Energy Resources; including 12 GW in 2024 alone

52%
below the national average carbon dioxide (“CO_2”) emissions rate

~90%
improvement in NextEra Energy’s overall company safety performance since 2003

~$97 - $107 B
expected capital deployment from 2024 through 2027

248%
ten-year total shareholder return (“TSR”), outperforming the S&P 500 Utilities Index

65%
better reliability than the national average for FPL

Above data as of 12/31/2024, unless otherwise indicated.

* Gigawatts (“GW”) shown includes assets operated by NextEra Energy Resources, including those owned by XPLR Infrastructure, LP (“XPLR”) at NextEra Energy’s ownership share, as of 12/31/2024; excludes assets which have been sold to third parties but continue to be operated by NextEra Energy Resources.

BUSINESS HIGHLIGHTS

NextEra Energy’s overall operational and financial performance was strong in 2024, despite challenges in the macroeconomic environment. NextEra Energy continued to deliver robust financial performance on an annual and multi-year basis.

For the full year 2024, NextEra Energy reported net income attributable to NextEra Energy on a GAAP basis of $6.946 billion, or $3.37 per share. We achieved company-record adjusted earnings** of $7.063 billion and adjusted EPS** of $3.43.

** This measure is not a financial measure calculated in accordance with accounting principles generally accepted in the United States of America (“GAAP”). See Appendix A to this proxy statement for a reconciliation of this non-GAAP financial measure to the most directly comparable GAAP financial measure.

These significant accomplishments came as NextEra Energy continued to be a leader among the ten largest U.S. utilities (based on market capitalization**) in many financial metrics, as shown below.

NEXTERA ENERGY RANK VS. TEN LARGEST U.S. UTILITIES BASED ON MARKET CAP**

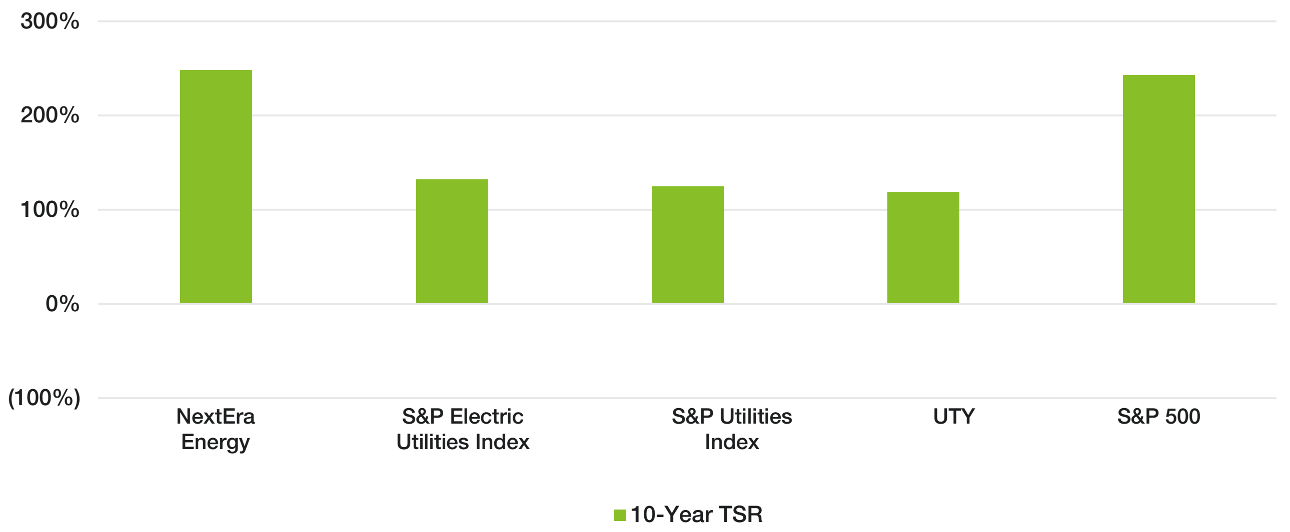
METRIC	RANK	DETAIL
Adjusted EPS Growth*	#1	3-, 5-, 7- and 10-year
Adjusted return on equity ("ROE")*	#1	1-, 3-, 5-, 7- and 10-year

* This measure is not a financial measure calculated in accordance with GAAP. See Appendix A to this proxy statement for a reconciliation of this non-GAAP financial measure to the most directly comparable GAAP financial measure. See the 2024 Financial Performance Matrix section on page 48 for more information on how the rankings are determined.

** Market capitalization is as of December 31, 2024; rankings are sourced from FactSet Research Systems Inc.

Ultimately, the Company's financial and operational performance is reflected in the increased value of its common stock. The chart below compares the Company's TSR for the 10-year period ended December 31, 2024 to the TSRs of the S&P 500 Electric Utilities Index, the S&P 500 Utilities Index, the UTY and the S&P 500. NextEra Energy outperformed all of these indices over the period shown.

NEXTERA ENERGY 10-YEAR TOTAL SHAREHOLDER RETURN THROUGH 12/31/2024 VS. VARIOUS INDICES(1)



NEXTERA ENERGY VS. INDICES	10-YEAR TSR
NextEra Energy	248%
S&P 500 Electric Utilities Index, total return	132%
S&P 500 Utilities Index, total return	125%
UTY, total return	119%
S&P 500, total return	243%

(1) Source: FactSet Research Systems Inc.

GOVERNANCE HIGHLIGHTS

DIRECTOR INDEPENDENCE	» 11 of 12 director nominees are independent » Chief executive officer ("CEO") is the only non-independent director » All members of the Audit Committee, Compensation Committee, Finance & Investment Committee and Governance & Nominating Committee are independent directors
BOARD LEADERSHIP	» Independent lead director ("Lead Director") selected by the independent directors » Lead Director has strong role and significant governance duties, including chairing regularly scheduled executive sessions of independent directors » As part of our 2024-2025 annual shareholder outreach program, Lead Director communicated directly with shareholders of 26.2% of outstanding shares
BOARD ACCOUNTABILITY	» All directors stand for election annually and the Board has adopted a resignation policy for directors who fail to receive the required vote in uncontested elections » Simple majority voting standard for all uncontested director elections » Shareholders of 20% or more of the outstanding shares may call a special meeting » No shareholder rights ("poison pill") plan » No supermajority vote requirements in the Company's Bylaws
BOARD EVALUATION & EFFECTIVENESS	» Annual Board and committee self-evaluations » Annual independent director evaluation of the chairman
BOARD COMPOSITION & REFRESHMENT	» Balance of new and experienced directors, with tenure of director nominees averaging 6.5 years » Specified retirement age for directors » 33% of director nominees are women » Average age of director nominees is 63 years » 25% of director nominees are ethnically diverse
DIRECTOR ENGAGEMENT	» All current directors attended 100% of Board and their assigned committee meetings » Board amended the Corporate Governance Principles & Guidelines to expressly address director time commitments
CLAWBACK & ANTI-HEDGING POLICIES	» Recoupment or clawback policy to recover certain executive pay in line with the New York Stock Exchange ("NYSE") rules » Policy prohibiting short sales, hedging and margin accounts
SHARE OWNERSHIP	» CEO required to hold shares equivalent to 7x base salary » All senior executives required to hold shares equivalent to 3x base salary » Directors required to hold shares equivalent to 7x the cash portion of their annual retainer
PROXY ACCESS	» Available to a shareholder, or group of up to 20 shareholders, owning 3% of the Company's outstanding shares for at least 3 years » May nominate candidates for the greater of 2 directorships or up to 20% of the membership of the Board

SUSTAINABILITY HIGHLIGHTS

Sustainability Report

In 2024, the Company published its annual sustainability report (the "2024 Sustainability Report"). Highlights of the 2024 Sustainability Report include:

- continued alignment with the Task Force on Climate-Related Financial Disclosures ("TCFD") framework;
- disclosure of Scope 1, Scope 2 and partial Scope 3 greenhouse gas emissions ("GHG") as verified by an independent third party; and
- Board oversight of those efforts and a discussion of the sustainability strategies of the Company's principal subsidiaries, FPL and NextEra Energy Resources.

The 2024 Sustainability Report discusses FPL's best-in-class value proposition of low customer bills, high reliability, diverse energy solutions and excellent customer service and NextEra Energy Resources' continued focus on building a diversified energy mix with an emphasis on growing its world-leading portfolio of energy projects.

The 2024 Sustainability Report details the Company's sustainability accomplishments and goals. Included among them, for 2023 unless otherwise indicated, are discussions of:

Emissions The Company's aspiration is to eliminate CO_2 emissions from its operations by 2045 if cost effective and good for customers and shareholders	**↓ 50%** The Company's CO_2 emissions rate was below the national average	FPL's generation fleet is one of the most efficient in the country, saving Florida customers nearly \$16 B in avoided fuel costs	**~$134 B** of infrastructure capital deployed since 2013
TALENTED TEAM More than 16,000 employees with diverse skill sets across various operations in 49 states	**COMMUNITY WELL-BEING** We have contributed approximately \$30 M and nearly 55,000 volunteer hours in our communities	**SUSTAINABILITY FOCUS** The Board's oversight process of sustainability issues, with a particular focus on the sustainability of our business	**SHAREHOLDER ENGAGEMENT** Our successful shareholder engagement efforts, which ensure that the Company's management and Board better understand shareholder priorities and perspectives

The 2024 Sustainability Report also includes certain disclosure within the following established environmental reporting frameworks:

- The Sustainability Accounting Standards Board;
- Edison Electric Institute's ESG/Sustainability Quantitative Metrics; and
- United Nations Sustainability Development Goals.

The Company also publishes its EEO-1 reports, available at https://www.investor.nexteraenergy.com/sustainability/sustainability-resources under Related Information.

Additionally, in 2024, the Company again participated in the Carbon Disclosure Project ("CDP") survey.

CDP
DISCLOSURE INSIGHT ACTION

The Company's 2024 Sustainability Report is available at:

Board oversight

The entire NextEra Energy Board, led by the chairman, has oversight of risks and opportunities, including their impacts on the Company's strategy. The Board understands the impacts of risks and opportunities on the Company's future growth and prioritizes them. At every scheduled Board meeting, the Board performs a review of the Company's performance against business objectives and key risks and opportunities for the Company. The Board also holds an annual strategy session devoted to discussing, debating and validating management's overall strategy. Oversight of physical environmental risks includes discussion of physical risks from hurricanes, emissions-related government policies, incentives and regulations, emissions-reduction initiatives, renewable energy, trends and business plans, and emerging diverse energy technologies, among others. The Board's Governance & Nominating Committee is specifically tasked with overseeing the Company's material risks that are environmental or social in nature, along with its sustainability efforts and initiatives.

The Board also has oversight of certain social topics relevant to the Company. The Board reviews the Company's talent management strategy at least annually, including human capital data. This review includes the Company's talent pipeline and the Company's internship program.

Information security and oversight of artificial intelligence

NextEra Energy's Audit Committee receives regular reports on the key risks facing the Company from the Corporate Risk Committee leader and also receives frequent reports from the Company's Internal Auditor about the results of reviews of cybersecurity and information security governance. Additionally, the Audit Committee discusses with management, at least annually, emerging artificial intelligence ("AI") developments and the Company's risk oversight with respect to AI. In February 2025, the Audit Committee Charter was amended to include the foregoing responsibilities and oversight. The Board receives cybersecurity dashboards in connection with each of its meetings to facilitate oversight, and biannually it receives a cybersecurity report from the Company's chief information officer and its vice president, IT infrastructure & cybersecurity.

Varying leading third parties periodically assess the Company's alignment with the U.S. Department of Energy's Cyber Capability Maturity Model (a/k/a C2M2) standard, which is the predominate cybersecurity framework for the U.S. electric utility industry. NextEra Energy has a comprehensive cybersecurity training program in which all employees receive education and training on prevention of cybersecurity problems and on privacy and data protection.

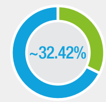
Shareholder engagement and annual shareholder outreach program

The Company engages with shareholders on a regular basis and provides information through multiple channels. We believe our shareholder engagement efforts allow us to better understand our shareholders' priorities and perspectives and enable us to effectively address the issues that matter the most to our shareholders.

In 2024, we reached out to our 50 largest shareholders, representing approximately 54.69% of our shares outstanding, and offered to engage on matters important to them, including governance, technology and risk mitigation. We held engagements with shareholders representing approximately 32.42% of the Company's shares outstanding and received valuable feedback on our Board structure and governance program. Our Lead Director, Amy B. Lane, participated in engagements with many of our top ten largest shareholders representing 26.23% of our shares outstanding. The feedback we received was shared with the full Board and has been considered in certain enhancements to our public disclosures and governance practices. We have made some additions to our related disclosures as described in more detail on page 7.

KEY SHAREHOLDER ENGAGEMENT HIGHLIGHTS

WE CONTACTED	WE ENGAGED WITH
50 of our largest shareholders	13 shareholders, who provided valuable feedback
REPRESENTING	**REPRESENTING**
~54.69% of shares outstanding (including all top 50 shareholders)	~32.42% of shares outstanding



We received a positive response from our 2023-2024 outreach efforts, resulting in continued outreach into 2025. Feedback from our engagements revealed consistent areas of focus for shareholders: Board structure, governance and technology and risk management. Shareholders' general sentiment remained positive, particularly regarding the increased transparency of our Board structure and Board refreshment. Additionally, shareholders emphasized the importance of Board succession planning and new director onboarding, and they confirmed the importance of having access to clear disclosure about the Company's governance. Shareholders also highlighted the need for Board oversight of new and evolving risks, including AI, cybersecurity, changing macroeconomic conditions and supply chain management.

WHAT WE HEARD	OUR RESPONSE
Some shareholders highlighted the importance of Board succession planning and new director onboarding	» The Board engages in an annual self-evaluation process conducted by the Governance & Nominating Committee, which includes surveying directors to assess the effectiveness of Board oversight and composition, and to solicit input for improvements. Recommendations are incorporated into Board processes and agenda topics. Additionally, the Board reviews criteria for skills, experience, background and capability and evaluates the process for identifying, considering, recruiting and nominating prospective members.
Shareholders expressed expectations for ongoing review of disclosure in relation to Board composition and Director competencies	» The 2024 proxy statement marked the initial integration of an additional disclosure table regarding the qualifications and background of each member of our Board, incorporating direct feedback from our shareholder outreach program.
Shareholders expressed interest in Board oversight of new and evolving risks, including AI, cybersecurity, changing macroeconomic conditions and supply chain	» The Board and the Audit Committee conduct ongoing risk oversight. In addition, the Board engages regularly with the Company's Executive Vice President, Chief Risk Officer, Terrell Kirk Crews II, who inaugurated the role in May 2024 with a team focused on continued efforts to address both risk mitigation efforts and opportunities in the Company's business.
Shareholders expressed an interest in AI and technology developments	» The Company continues to evolve with the ever-changing energy and technology needs of its customers, and it continues to evaluate how to modernize its business while mitigating risks. In February 2025, the Audit Committee Charter was amended in order to assign risk oversight with respect to the Company's use of AI to the Audit Committee.
Shareholders expressed interest in increased power demand and how we will address growing needs	» The Board works continuously with management on the strategic direction of the Company, acknowledging that addressing increased load growth requires all forms of energy, and NextEra Energy is well positioned to lead in developing new power and integrating a diversified grid.

Business of the Annual Meeting

PROPOSAL 1: ELECTION AS DIRECTORS OF THE NOMINEES SPECIFIED IN THIS PROXY STATEMENT

The Board is currently composed of 12 members. Upon the recommendation of the Governance & Nominating Committee, the Board has nominated each of the 12 incumbent members listed below for election as directors at the 2025 annual meeting. Unless you specify otherwise, your proxy will be voted **FOR** the election of the listed nominees. If any nominee becomes unavailable for election, which is not currently anticipated, proxies instructing a vote for that nominee may be voted for a substitute nominee selected by the Board or, in lieu thereof, the Board may reduce the number of directors by the number of nominees unavailable for election.

Nicole S. Arnaboldi

James L. Camaren

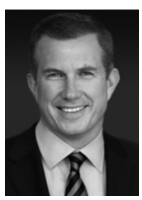
Naren K. Gursahaney

Kirk S. Hachigian

Maria G. Henry

John W. Ketchum

Amy B. Lane



Geoffrey S. Martha

David L. Porges

Deborah L. “Dev” Stahlkopf

John A. Stall

Darryl L. Wilson

The Board believes its current size is appropriate because it facilitates substantive discussions among Board members, provides for sufficient staffing of Board committees and allows for contributions by directors having a broad range of skills, expertise, industry knowledge and diversity of opinion. Directors serve until the next annual meeting of shareholders or until their respective successors are elected and qualified.

Board refreshment

The Board and the Governance & Nominating Committee engage in a continuous process of considering the mix of skills and experience needed by the Board as a whole to discharge its responsibilities. Six of the director nominees have a tenure of less than five years. In 2024, the Governance & Nominating Committee discussed Board composition, Board refreshment and Board recruiting at every committee meeting.

The Company has a director retirement policy. Generally, no person who has attained the age of 72 years by the date of election is eligible for election as a director. However, the Board may, by unanimous action (excluding the affected director), extend a director’s eligibility for one or two additional years, in which event the director will not be eligible for subsequent election as a director if he or she would have attained the age of 73 or 74 by or prior to the date of the election. Amy B. Lane will have reached the normal retirement age of 72 years by the date of the 2025 annual meeting. Upon review of the matter, the Governance & Nominating Committee recommended, and the Board unanimously approved, extending the retirement date for Ms. Lane and nominating her for election at the 2025 annual meeting. In reaching this decision, the Governance & Nominating Committee and the Board considered the high number of director retirements and new members of the Board who have joined in recent years and the need for the Board to retain Ms. Lane, who brings important experience and knowledge about the issues and strategy of the Company. The Governance & Nominating Committee and the Board also considered the extensive financial, leadership and strategy skills of Ms. Lane, among other skills and attributes. Furthermore, Ms. Lane has served the Company and the Board extremely well in the role of Lead Director and in other leadership roles on the Board.

Identifying and evaluating nominees for directors

The Governance & Nominating Committee uses a variety of methods for identifying and evaluating nominees for director. The Governance & Nominating Committee regularly assesses the appropriate size of the Board and whether any vacancies on the Board are expected due to retirement or otherwise. Candidates may come to the attention of the Governance & Nominating Committee through current Board members, professional search firms, shareholders or other persons. Candidates are evaluated at regular or special meetings of the Governance & Nominating Committee and may be considered at any time during the year. When considering candidates for the Board, the Governance & Nominating Committee considers all nominee recommendations, including those from shareholders, in the same manner. If any materials are provided by a shareholder in connection with the nomination of a director candidate, the materials are provided to the Governance & Nominating Committee. The Governance & Nominating Committee also reviews materials provided by professional search firms or other parties.

NextEra Energy's Corporate Governance Principles & Guidelines (the "Governance Guidelines") provide that, in identifying nominees for director, the Company seeks to achieve a mix of directors representing a diversity of skills, experience, background and capability. In the Board's annual self-evaluation, it reviews the criteria for skills, experience and background reflected in the Board's membership and also reviews the Board's process for identification, consideration, recruitment and nomination of prospective Board members.

Geoffrey S. Martha is a nominee for election to the Board this year who currently serves on the Board and previously has not been elected by the Company's shareholders. Mr. Martha was identified by the recruiting efforts of management and the Governance & Nominating Committee members. Mr. Martha was interviewed by each of the members of the Governance & Nominating Committee and by Mr. Ketchum. The Governance & Nominating Committee evaluated Mr. Martha's qualifications, experience and background based on the criteria outlined in the Governance Guidelines. The Governance & Nominating Committee took special note that, as the current CEO of a global healthcare technology company, Mr. Martha would bring valuable expertise in finance and business, along with leadership and specialized expertise in capital markets, global business, technology and manufacturing. Following evaluation by the Governance & Nominating Committee, Mr. Martha was interviewed by the other members of the Board and was appointed to the Board in July 2024.

Director resignation policy

Under the NextEra Energy, Inc. Amended and Restated Bylaws (the "Bylaws"), in an uncontested election, directors are elected by a majority of the votes cast. The Board has adopted a Policy on Failure of Nominee Director(s) to Receive a Majority Vote in an Uncontested Election ("Director Resignation Policy"), the effect of which is to require that, in any uncontested director election, any incumbent director who is not elected by the required vote must offer to resign and the Board will determine whether or not to accept the resignation within 90 days of the certification of the shareholder vote. The Company will report the action taken by the Board under the Director Resignation Policy in a publicly available forum or document. The Bylaws provide that, in a contested election, director nominees are elected by a plurality of the votes cast.

Director qualifications

The Governance Guidelines and the Governance & Nominating Committee Charter identify Board membership qualifications, including experience, skills and attributes, that are considered by the Governance & Nominating Committee in recommending non-employee nominees for Board membership. In addition to the membership qualifications identified in the Governance Guidelines, no person will be considered for Board membership who is an employee or director of a business in significant competition with the Company or of a major or potentially major customer, supplier, contractor, counselor or consultant of the Company, or an executive officer of a business where a Company employee-director serves on the board of such other business.

The chart below provides a summary of the collective competencies of the current Board and explains why these are important:

DIRECTOR QUALIFICATIONS	COMPETENCIES AND RELEVANCE TO NEXTERA ENERGY	BOARD COMPOSITION
Individuals who have served as a public company CEO	**PUBLIC COMPANY CEO EXPERIENCE** Experience serving as a CEO provides unique perspectives to help the Board independently oversee NextEra Energy's CEO and management. Having this experience also increases the Board's understanding and appreciation of the many facets of running a public company, including strategic planning, financial reporting, compliance and risk oversight.	50%
Demonstrated expertise in managing large, relatively complex organizations, such as leadership roles of a significant company or organization	**STRATEGY EXPERTISE** Our Company operates in a quickly changing industry with new developing technologies. Having experience in developing and implementing strategic plans helps enable the Board to oversee and pivot in rapidly changing environments.	100%
	OPERATIONS MANAGEMENT AND LEADERSHIP Our Company has a strong focus on cost and customer value, as well as innovation. Having experience with operations assists the Board in understanding the issues that the Company faces in achieving its industry-leading operating and maintenance ("O&M") initiatives and reducing costs.	67%
	MERGERS & ACQUISITIONS EXPERIENCE Our Company from time to time acquires and disposes of businesses and assets. An understanding of mergers & acquisitions helps the Board evaluate any future transactions and any associated opportunities and risks.	83%
Experience leading a utility, energy company or other highly regulated organization, such as CEO or other leadership position	**UTILITY/REGULATED INDUSTRY LEADERSHIP** As a company in a highly regulated industry, experience in the utility industry or another regulated industry assists the Board in understanding the regulatory issues that the Company faces.	42%
	ENERGY INDUSTRY LEADERSHIP It is important that the Board understand the energy industry and the complete energy industry value chain. Energy industry leadership assists the Board in understanding all aspects of the ongoing energy transition.	42%
Financial or other risk management expertise	**FINANCIAL** Our Company's business involves complex financial management, capital allocation and reporting issues. An understanding of finance and financial reporting is valuable in order to promote effective capital allocation and robust controls and oversight of accurate financial reporting.	75%
	RISK MANAGEMENT The scale, scope and complexity of our Company's business raises a variety of interdependent risks. Experience in effectively identifying, prioritizing and managing a broad spectrum of risks can help the Board appreciate, anticipate and oversee the Company in managing the risks that face its various businesses.	92%

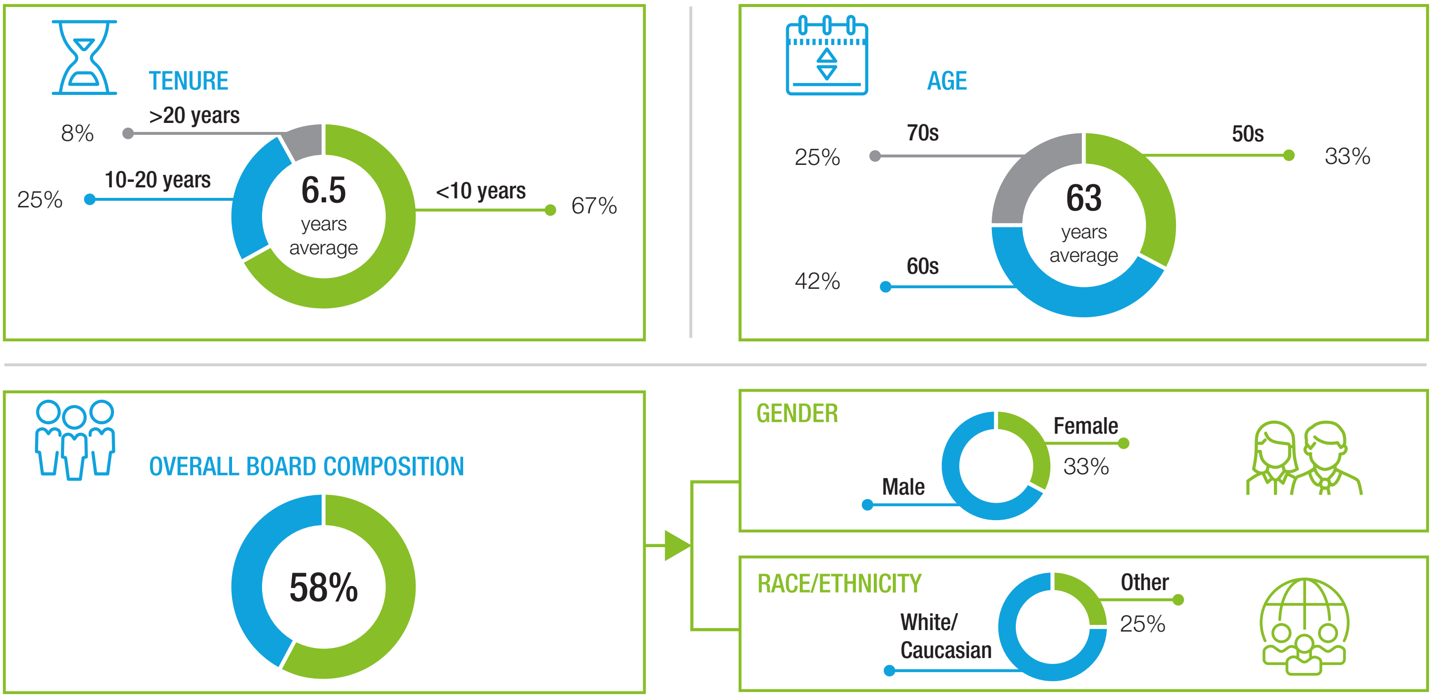
DIRECTOR QUALIFICATIONS	COMPETENCIES AND RELEVANCE TO NEXTERA ENERGY	BOARD COMPOSITION
Experience serving in senior customer facing roles or in industries where customer service is strategically important	**MARKETING, SALES AND CUSTOMER SERVICE EXPERIENCE** FPL services over six million customer accounts in the state of Florida. NextEra Energy Resources also has a number of customer and consumer facing businesses serving thousands of customers. Experience in marketing, sales and customer service helps the Board oversee FPL's best-in-class customer value proposition and NextEra Energy Resources' growing consumer facing businesses.	58%
Experience in managing engineering and construction projects	**ENGINEERING AND CONSTRUCTION LEADERSHIP** In 2024, the Company invested approximately $25 billion in energy infrastructure and NextEra Energy Resources commissioned approximately 6,000 MW of renewable energy projects. Board experience in engineering and construction leadership assists the Board in its oversight of our large-scale capital investments and on our timely and on-budget capital project execution.	42%
Experience with information technology and cybersecurity	**INFORMATION TECHNOLOGY LEADERSHIP** Oversight of the protection of customer information and cybersecurity is critical to providing reliable electric service at both FPL and NextEra Energy Resources. Board experience in information technology leadership assists the Board in its oversight of our cybersecurity programs.	42%
Experience overseeing or managing environmental practices, with an understanding of policy, risks, regulations and compliance obligations	**ENVIRONMENTAL** Our Board, led by our chairman, prioritizes governance of sustainability-related risks and opportunities. During each Board meeting, we review our performance, assess key risks and discuss business objectives. We also have an annual session dedicated to evaluating and validating our overall management strategy. The Board's oversight of sustainability, which is exercised through the Board's committees and in particular using a framework led by its Governance & Nominating Committee, includes discussions of physical environmental risks, such as hurricanes, emissions-related government policies, incentives and regulations, emissions-reduction initiatives, renewable energy trends and business plans, and emerging energy technologies, among other matters.	83%

The Board views itself as a cohesive whole consisting of members who together serve the interests of the Company and its shareholders. The Board is comprised of directors with a mix of backgrounds, knowledge and skills that the Board considers relevant and beneficial in fulfilling its oversight role. The chart below provides a summary of each current individual director's most relevant experience and background:

	Arnaboldi	Camaren	Gursahaney	Hachigian	Henry	Ketchum	Lane	Martha	Porges	Stahlkopf	Stall	Wilson
Experience												
Public Company CEO Experience		✓	✓	✓		✓		✓	✓			
Financial Industry Experience & Leadership	✓	✓	✓	✓	✓	✓	✓	✓	✓			
Strategy Expertise	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Operations Management & Leadership			✓	✓	✓	✓		✓	✓		✓	✓
International Experience	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓
Utility / Regulated Industry Leadership	✓	✓				✓			✓		✓	
Political / Legislative Experience						✓				✓		
Energy Industry Leadership						✓		✓	✓		✓	✓
Engineering & Construction Industry Experience		✓	✓			✓			✓		✓	
Nuclear Operations Leadership						✓					✓	
Risk Management Leadership	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓
Mergers & Acquisitions Experience	✓	✓	✓	✓	✓	✓	✓	✓	✓			✓
Information Technology / Cyber Experience			✓		✓	✓		✓		✓		
Investor Relations Management		✓	✓	✓	✓	✓		✓	✓			
Marketing / Sales / Customer Service Experience & Leadership	✓		✓	✓	✓	✓	✓					✓
New Business Development/Development	✓	✓	✓	✓	✓	✓	✓	✓	✓			✓
Human Resources Development	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Trading/Derivatives		✓				✓	✓					
Environmental	✓	✓	✓	✓		✓	✓	✓	✓		✓	✓
Board Composition												
Female	✓				✓		✓			✓		
Male		✓	✓	✓		✓		✓	✓		✓	✓
Asian/Indian			✓									
Black/African American												✓
Hispanic/Latino		✓										
White/Caucasian	✓			✓	✓	✓	✓	✓	✓	✓	✓	

Director profile and Board composition

The charts below reflect the composition of the current Board members.



Director nominee biographies

NICOLE S. ARNABOLDI

Age 66

Independent director since 2022

Board Committees

- Audit
- Finance & Investment

Public Company Boards

- Manulife Financial Corporation (since 2020)

Career Highlights

Ms. Arnaboldi has been a partner at Oak Hill Capital Management, a private equity firm, since 2021. She was previously the vice chairman of Credit Suisse Asset Management and a managing director of Credit Suisse Securities Corp. from 2000 to 2019. Prior to her roles at Credit Suisse, a global investment bank and financial services firm, Ms. Arnaboldi served as a managing director of its predecessor, Donaldson Lufkin and Jenrette, in the firm's venture capital group from 1985 to 1992 and then in its private equity group, where she became a managing director in 1996.

Qualifications

Ms. Arnaboldi has over 35 years of leadership experience in financial services and private equity, including her service as vice chairman of Credit Suisse Asset Management and as a partner of Oak Hill Capital Management. She has a wealth of finance and business expertise, along with a proven track record as an experienced leader and strategist in investment banking and private equity for more than three decades. Ms. Arnaboldi holds a law degree from Harvard Law School, a Master of Business Administration degree from the Harvard Business School and a Bachelor of Arts degree from Harvard College.

JAMES L. CAMAREN

Age 70

Independent director since 2002

Board Committees

- Compensation
- Finance & Investment

Career Highlights

Mr. Camaren is a private investor. Until May 2006, he was chairman and CEO of Utilities, Inc. which was one of the largest investor-owned water utilities in the United States until March 2002 when it was acquired by Nuon, a Dutch company, which subsequently sold Utilities, Inc. in April 2006. He joined Utilities, Inc. in 1987 and served successively as vice president of business development, executive vice president, and vice chairman, becoming chairman and CEO in 1996.

Qualifications

Mr. Camaren has 19 years of leadership experience with a large, regulated investor-owned utility. During the years he served as chairman and CEO, the utility had customer growth at a rate that exceeded the industry average and acquired and integrated over 40 utilities. In addition, Mr. Camaren has experience in managing capital expenditures, environmental compliance, regulatory affairs and investor relations.

NAREN K. GURSAHANEY

Age 63

Independent director since 2014

Board Committees

- Audit (Chair)
- Executive
- Governance & Nominating

Career Highlights

Mr. Gursahaney is retired. He served as the president and CEO, and a member of the board of directors, of The ADT Corporation ("ADT"), a provider of security systems and services, from September 2012 until its acquisition by affiliated funds of Apollo Global Management LLC in May 2016. Prior to ADT's separation from Tyco International Ltd. ("Tyco") in September 2012, Mr. Gursahaney served as president of Tyco's ADT North American Residential business segment and was the president of Tyco Security Solutions, then a provider of electronic security to residential, commercial, industrial and governmental customers and the largest operating segment of Tyco. Mr. Gursahaney joined Tyco in 2003 as senior vice president of operational excellence. He then served as president of Tyco Engineered Products and Services and president of Tyco Flow Control. Prior to joining Tyco, Mr. Gursahaney was president and CEO of GE Medical Systems Asia, where he was responsible for the company's sales and services business in the Asia-Pacific region. During his 10-year career with GE, Mr. Gursahaney held senior leadership roles in services, marketing and information management.

Qualifications

Mr. Gursahaney has extensive operations, strategic planning and leadership experience in global manufacturing and services businesses serving residential, commercial, industrial and governmental customers gained as the CEO of a public company providing security systems and service. He also has extensive global operations, information technology and service experience gained as the president and CEO of the Asia-Pacific division of a medical diagnostic and imaging manufacturer. He has an MBA from the University of Virginia and a Bachelor of Science degree in mechanical engineering from Pennsylvania State University.

KIRK S. HACHIGIAN

Age 65

Independent director since 2013

Board Committees

- Compensation (Chair)
- Executive
- Governance & Nominating

Public Company Boards

- Allegion plc (since 2013: expected retirement in June 2025)
- PACCAR, Inc. (since 2008)
- L3 Harris Technologies, Inc. (since 2023)

Career Highlights

Mr. Hachigian is retired. He served as chairman of the board of JELD-WEN Holding, Inc., a manufacturer of windows and doors, from February 2014 until May 2018. He also served as CEO of JELD-WEN Holding, Inc. from April 2014 until December 2016. He served as chairman, president and CEO of Cooper Industries plc ("Cooper"), a publicly held electrical equipment and tool manufacturer, until Cooper's acquisition by Eaton Corporation plc in November 2012. He was named chairman of Cooper in 2006, CEO in 2005 and president in 2004.

Qualifications

Mr. Hachigian has extensive leadership, operations and strategic planning experience gained through his prior service as the chairman, CEO and president of a global, publicly held manufacturer of electrical equipment and tools. He also has international leadership and operations experience gained through his prior service as the president and CEO of the Asia-Pacific operations of a lighting products manufacturer and in key management positions in Singapore and Mexico. In addition, Mr. Hachigian has financial and risk oversight experience developed through his prior service on the audit committee of another public company and as a prior member of the board of the Houston branch of the Federal Reserve Bank of Dallas. He has an MBA in finance from the Wharton School of Business and a Bachelor of Science degree in engineering from the University of California (Berkeley).

MARIA G. HENRY

Board Committees

- Audit
- Finance & Investment

Public Company Boards

- General Mills, Inc. (since 2016)
- NIKE, Inc. (since May 2023)

Age 58

Independent director since 2023

Career Highlights

Ms. Henry was chief financial officer of Kimberly-Clark Corporation, a global manufacturer of a wide range of products using advanced technologies in fibers, nonwovens and absorbency, from April 2015 through April 2022, and served as executive vice president and senior advisor of Kimberly-Clark Corporation from April 2022 until her retirement in September 2022. Prior to Kimberly-Clark, Ms. Henry was executive vice president and chief financial officer of the Hillshire Brands Company, formerly known as Sara Lee Corporation, from 2012 to 2014. She was the chief financial officer of Sara Lee's North American Retail and Foodservice business from 2011 to 2012. Prior to Sara Lee, Ms. Henry held various senior leadership positions in finance and strategy in three portfolio companies of Clayton, Dubilier & Rice, most recently as executive vice president and chief financial officer of Culligan International. She also held senior finance roles in several technology companies and began her career at General Electric.

Qualifications

Ms. Henry has extensive leadership experience in finance and strategy for large global public, private equity controlled, and smaller entrepreneurial companies across consumer, technology, manufacturing and distribution industries. She has had oversight responsibility for finance, treasury, investor relations, strategy, real estate and accounting. She also has experience overseeing information technology and risk, including cyber risk. Ms. Henry currently serves on the boards of directors of NIKE, Inc. and General Mills, Inc. She holds a Bachelor of Science degree in finance from the University of Maryland.

JOHN W. KETCHUM

Board Committees

- Executive (Chair)
- Nuclear

Public Company Boards

- XPLR Infrastructure, LP (since 2017)

Age 54

Director since 2022

Career Highlights

Mr. Ketchum has been president and chief executive officer and a director of NextEra Energy since March 2022 and chairman of the Board since July 2022. He has also served as chairman of NextEra Energy's subsidiary, Florida Power & Light Company (which has no publicly traded stock), since February 2023. Prior to his succession to the role of chief executive officer, he served as president and chief executive officer of NextEra Energy Resources, the Company's leading wholesale power generator in the U.S. Mr. Ketchum joined NextEra Energy in 2002 and has a diverse business, finance and legal background with a broad range of experiences across key executive roles and NextEra Energy, NextEra Energy Resources and XPLR. Mr. Ketchum is chairman of the board of XPLR, which is a limited partnership that has an ownership interest in an energy infrastructure portfolio with long-term, stable cash flows (in which the Company owns an underlying 52.5% interest).

Qualifications

Mr. Ketchum has a diverse business, finance and legal background with a broad range of experiences gained through his key executive roles at NextEra Energy, NextEra Energy Resources and XPLR. During his 22 years with NextEra Energy, Mr. Ketchum has led the execution of various strategic initiatives across the enterprise and has been instrumental in the expansion of the Company's renewable generation fleet. While CEO of NextEra Energy Resources, Mr. Ketchum oversaw the largest three-year capital investment program in NextEra Energy Resources' history, as well its most successful period of new renewables origination, leading to a near doubling of the size of the renewables backlog during this period. In addition, he oversaw a nearly $5 billion, three-year capital recycling program, the largest in NextEra Energy Resources' history. Mr. Ketchum holds a Master of Laws degree in taxation and a Juris Doctor from the University of Missouri — Kansas City School of Law. Mr. Ketchum holds a Bachelor of Arts degree in economics and finance from the University of Arizona. He also completed the Emerging CFO — Strategic Financial Leadership Program at Stanford University.

AMY B. LANE

Age 72

Independent director since 2015

Board Committees

- » Compensation
- » Executive
- » Governance & Nominating (Chair)

Public Company Boards

- » FedEx Corp. (since 2022)
- » The TJX Companies, Inc. (since 2005)

Career Highlights

Ms. Lane retired in 2002 as managing director and group leader of the global Retailing Investment Banking Group of Merrill Lynch & Co., Inc. ("Merrill Lynch"), an investment banking firm. Prior to joining Merrill Lynch in 1997, she was a managing director at Salomon Brothers, Inc. ("Salomon Brothers"), an investment banking firm, where she founded and led the retail industry investment banking unit, having joined Salomon Brothers in 1989.

Qualifications

Ms. Lane has 26 years of leadership experience with financial services, capital markets, finance and accounting, capital structure, and acquisitions and divestitures in the financial services industry, as well as extensive experience in management, leadership and strategy. In her role with Merrill Lynch, she led and worked on mergers and acquisitions and equity and debt transactions for a wide range of major retailers. Prior to joining Merrill Lynch, she was a managing director at Salomon Brothers, which she joined in 1989 and where she founded and led the retail industry investment banking unit. Ms. Lane has an MBA from the Wharton School of Business.

GEOFFREY S. MARTHA

Age 55

Independent director since 2024

Board Committees

- » Finance & Investment

Public Company Boards

- » Medtronic plc (since 2020)

Career Highlights

Mr. Martha is chairman and chief executive officer of Medtronic plc, a global healthcare technology company ("Medtronic"). He served as Medtronic's president from 2019-2020. Previously, Mr. Martha served as executive vice president and president of the Restorative Therapies Group, a role he held from 2015 to 2019. He joined Medtronic in 2011 as senior vice president, strategy and business development. Prior to Medtronic, he served as managing director of business development at GE Healthcare from 2007 to 2011; general manager for GE Capital Technology Finance Services from 2003 to 2007; senior vice president of business development for GE Capital Vendor Financial Services from 2002 to 2003; general manager for GE Capital Colonial Pacific Leasing from 2001 to 2002; and vice president of business development for Potomac Federal, the GE Capital federal financing investment bank, from 1998 to 2001.

Qualifications

Mr. Martha has extensive leadership experience in the healthcare technology and financial services industries. Mr. Martha has comprehensive experience leading strategic initiatives in commercial finance, business development, portfolio management and mergers and acquisitions. He holds a Bachelor of Science degree in finance from Pennsylvania State University, graduating with highest honors.

DAVID L. PORGES

Age 67

Independent director since 2020

Board Committees

- Executive
- Finance & Investment (Chair)
- Governance & Nominating

Career Highlights

Mr. Porges is retired. He was a non-employee member of the board of directors of Equitrans Midstream Corporation ("Equitrans") from November 2018 through December 2019 and was the chairman of the board of Equitrans from November 2018 to July 2019. He joined EQT Corporation ("EQT") in 1998 as senior vice president and chief financial officer and served as EQT's CEO from April 2010 to April 2011 and as CEO and chairman from April 2011 to February 2017. From February 2017 to March 2018, Mr. Porges served as EQT's executive chairman and as chairman and interim CEO from March 2018 to November 2018.

Qualifications

Mr. Porges has more than 20 years of leadership, finance, operations and mergers and acquisitions experience gained through his prior service as CEO and chairman of a publicly held energy industry company, as well as his prior service as the chief financial officer of that energy company. Mr. Porges also has experience with capital markets, finance and mergers and acquisitions gained through his prior service with an investment bank concentrating on the energy industry. Mr. Porges has an MBA from Stanford University.

DEBORAH L. "DEV" STAHLKOPF

Age 55

Independent director since 2023

Board Committees

- Audit
- Compensation

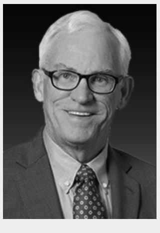
Career Highlights

Ms. Stahlkopf joined Cisco Systems, Inc. ("Cisco"), a global technology company, in August 2021 as executive vice president and chief legal officer. Prior to joining Cisco, she held several senior roles at Microsoft Corporation ("Microsoft") over the course of 14 years, including corporate vice president, general counsel and corporate secretary, corporate, external and legal affairs from April 2018 to July 2021, vice president and deputy general counsel from December 2015 to April 2018 and associate general counsel from December 2010 to December 2015. Prior to joining Microsoft, she practiced law in the Seattle area at Perkins Coie, specializing in employment and labor law and at Cooley Godward, LLP, focusing on corporate and technology transactions.

Qualifications

Ms. Stahlkopf has extensive experience in legal strategy, including key issues including intellectual property, privacy and security, internet governance, cross-border data issues, geopolitical matters, and public policy priorities. She also has extensive experience in labor and employment law. She received her law degree from the University of Arizona, a Master of Arts degree in Philosophy from Duke University and a Bachelor of Arts degree in English and philosophy from the University of Washington.

JOHN A. STALL



Age 70

Independent director since 2022

Board Committees

- Finance & Investment
- Nuclear (Chair)

Career Highlights

Mr. Stall retired from NextEra Energy in 2010, where he served in numerous nuclear leadership roles. He served as president of NextEra Energy's nuclear division from 2009 to 2010, as senior vice president and chief nuclear officer from 2001 to 2009, as vice president, nuclear engineering from 2000 to 2001 and vice president of NextEra Energy's St. Lucie nuclear generating station from 1996 to 2000. He also served in leadership roles at Dominion Energy, Inc.'s North Anna nuclear generating station from 1977 until 1996.

Qualifications

Mr. Stall has substantial nuclear expertise, operations and engineering experience and leadership experience. He has over 40 years of experience in nuclear generation through his career at both Dominion Energy, Inc. and NextEra Energy. He previously held a senior reactor operator license issued by the Nuclear Regulatory Commission and is a previously licensed professional engineer in the Commonwealth of Virginia. He served as the chair of an independent nuclear safety advisory committee for a publicly-traded electric utility that operates multiple nuclear generating units. He served as a member of the Institute of Nuclear Power Operations National Academy of Nuclear Training Accrediting Board from 2008 to 2019. Mr. Stall graduated from the University of Florida and holds a Bachelor of Science degree in nuclear engineering. He received his MBA from Virginia Commonwealth University.

DARRYL L. WILSON

Age 61

Independent director since 2018

Board Committees

- Audit
- Compensation

Public Company Boards

- Eaton Corporation plc (since 2021)
- Primerica, Inc. (since 2024)
- Solventum Corp. (since 2024)

Career Highlights

Mr. Wilson was vice president, commercial of GE Power, a business of GE, from June 2017 until his retirement in December 2017. From January 2016 to June 2017, he was vice president & chief commercial officer of GE Energy Connections and, from January 2013 to January 2016, he was vice president & chief commercial officer of GE Distributed Power. From July 2008 to January 2013, he was president & CEO of GE Aeroderivative Products. Prior roles also include president & CEO of GE Consumer Products, Europe Middle-east, Africa and India, based in Budapest, Hungary and London, England. He also served as president & CEO of GE Consumer and Industrial, Asia-Pacific and India based in Shanghai, China. Additionally, Mr. Wilson spent 6 years in progressive executive leader roles with British Petroleum — North America in business operations and regional fuel and lubricant distribution management positions.

Qualifications

Mr. Wilson has extensive leadership and international experience in business operations, commercial management, global manufacturing, mergers and acquisitions and services as a result of his senior leadership roles for a global manufacturer and service provider of power generation, power electronics, distribution, motors, power management, appliances and lighting products.
Mr. Wilson has finance and financial markets experience as former chairman of the board of directors, Houston Branch — Dallas Federal Reserve Bank and serving on the audit and investment committees on other public and non-profit boards.
Mr. Wilson received an MBA in Marketing from Indiana University and a Bachelor of Arts degree in business administration from Baldwin Wallace College.

Unless you specify otherwise in your voting instructions, your proxy will be voted **FOR** election of each of the nominees.

The Board unanimously recommends a vote **FOR** the election of all nominees.

PROPOSAL 2: RATIFICATION OF APPOINTMENT OF DELOITTE & TOUCHE LLP AS NEXTERA ENERGY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2025

The Audit Committee appoints the Company's independent registered public accounting firm. It has appointed Deloitte & Touche LLP ("Deloitte & Touche") as the independent registered public accounting firm for the fiscal year ending December 31, 2025 to audit the accounts of the Company and its subsidiaries, as well as to provide its opinion on the effectiveness of the Company's internal controls over financial reporting. The members of the Audit Committee and the Board believe that the continued retention of Deloitte & Touche as the Company's independent registered public accounting firm is in the best interests of the Company and its shareholders.

The Audit Committee reviewed and considered:

- Whether retaining Deloitte & Touche is in the best interests of the Company and its shareholders.
- The professional qualifications of Deloitte & Touche and the lead audit and other senior engagement partners.
- The historic and current audit quality of service of Deloitte & Touche and the lead audit and other senior engagement partners, including the candidness of the communications and interactions with the Audit Committee, as well as their independent judgment and professional integrity and objectivity.
- Deloitte & Touche's capabilities and expertise in handling the breadth and complexity of the Company's operations and businesses, accounting policies and internal controls over financial reporting, including Deloitte & Touche's use of technology, specialists and subject matter experts and the sharing of industry insights, trends and emerging practices.
- Deloitte & Touche's tenure as independent auditor, including the benefits of its institutional knowledge of the Company and its history and familiarity with the Company's businesses, which enhances Deloitte & Touche's audit efficiency and effectiveness and provides cost efficiencies.
- The potential challenges, impact and advisability of selecting a different independent auditor, including the time and expense of transitioning to a new independent auditor.
- Deloitte & Touche's independence from the Company, noting that (i) Deloitte & Touche does not provide any non-audit services to the Company other than those deemed permissible, as described under "Independent Auditor Fees," and (ii) both the Company and Deloitte & Touche have controls and policies in place, including related to the applicable auditor independence rules and the mandatory rotation of the lead audit and other senior engagement partners, which helps ensure the continued independence and fresh perspectives of Deloitte & Touche.
- Deloitte & Touche's succession planning for rotation of key engagement partners.
- The appropriateness of Deloitte & Touche's fees relative to both audit quality and efficiency.
- External data on audit quality and performance, including recent Public Company Accounting Oversight Board ("PCAOB") reports on Deloitte & Touche and peer companies.

Although ratification of the Audit Committee's appointment of Deloitte & Touche as independent public accounting firm for 2025 is not required, the Board is submitting the selection of Deloitte & Touche to shareholders as a matter of good corporate practice. If shareholders do not ratify the appointment, the appointment will be reconsidered by the Audit Committee, although the Audit Committee may nonetheless decide to continue the retention of Deloitte & Touche as NextEra Energy's independent registered public accounting firm for 2025. Even if the appointment is ratified, the Audit Committee in its discretion may terminate the service of Deloitte & Touche at any time during the year if it determines that the appointment of a different independent registered public accounting firm would be in the best interests of NextEra Energy and its shareholders. Additional information on audit-related matters may be found on page 33 of this proxy statement.

Representatives of Deloitte & Touche are expected to be present at the annual meeting and will have an opportunity to make a statement and respond to appropriate questions from shareholders at the meeting.

Unless you specify otherwise in your voting instructions, your proxy will be voted **FOR** ratification of appointment of Deloitte & Touche as NextEra Energy's independent registered public accounting firm for 2025.

The Board unanimously recommends a vote **FOR** ratification of appointment of Deloitte & Touche LLP as NextEra Energy's independent registered public accounting firm for 2025.

PROPOSAL 3: APPROVAL, BY NON-BINDING ADVISORY VOTE, OF NEXTERA ENERGY'S COMPENSATION OF ITS NAMED EXECUTIVE OFFICERS AS DISCLOSED IN THIS PROXY STATEMENT

The Company is asking shareholders to cast an advisory vote on the compensation of the Company's named executive officers ("NEOs"), which is commonly called a "say-on-pay" vote, pursuant to section 14A of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Although this vote is not binding, it will provide information to the Compensation Committee regarding investor sentiment about the Company's executive compensation philosophy, policies and practices, which the Compensation Committee will be able to consider when making future determinations regarding NEO compensation. The Company plans to give shareholders the opportunity to cast an advisory vote on this matter annually. Following the vote on this proposal, the next opportunity will occur in connection with the Company's 2026 annual meeting.

The Company asks shareholders to approve this proposal by approving the following non-binding resolution:

> "**RESOLVED**, that the shareholders of NextEra Energy, Inc. approve, on an advisory basis, the compensation paid to the Company's NEOs, as disclosed in this proxy statement for the 2025 annual meeting of shareholders, including the Compensation Discussion & Analysis section, the compensation tables and the accompanying narrative discussion, pursuant to the compensation disclosure rules of the Securities and Exchange Commission (Item 402 of Regulation S-K)."

The fundamental objective of NextEra Energy's executive compensation program is to motivate and reward actions that will increase shareholder value, particularly over the longer term. The Compensation Committee believes the Company's executive compensation program reflects a strong pay-for-performance philosophy and is well-aligned with the short-term and long-term interests of shareholders and other important Company stakeholders, including customers and employees. A significant portion of each NEO's total compensation opportunity is performance-based and carries both upside and downside potential.

The Executive Compensation section of this proxy statement, beginning on page 35, provides a detailed discussion of the Company's compensation program for its NEOs. As an illustration of the success of our compensation program in incentivizing operational excellence and providing long-term value for shareholders, the chart below compares the Company's TSR for the 10-year period ended December 31, 2024 to the TSRs of the S&P 500 Electric Utilities Index, the S&P 500 Utilities Index, the UTY and the S&P 500. NextEra Energy outperformed all of these indices over the period shown.

NEXTERA ENERGY TOTAL SHAREHOLDER RETURN THROUGH 12/31/2024 VS. VARIOUS INDICES[1]

NEXTERA ENERGY VS. INDICES	10-YEAR TSR
NextEra Energy	248%
S&P 500 Electric Utilities Index, total return	132%
S&P 500 Utilities Index, total return	125%
UTY, total return	119%
S&P 500, total return	243%

(1) Source: FactSet Research Systems Inc.

Unless you specify otherwise in your voting instructions, your proxy will be voted **FOR** approval, by non-binding advisory vote, of NextEra Energy's compensation of its NEOs as disclosed in this proxy statement.

The Board unanimously recommends a vote **FOR** approval, by non-binding advisory vote, of NextEra Energy's compensation of its named executive officers, as disclosed in this proxy statement.

Information About NextEra Energy and Management

THE COMPANY'S SECURITIES TRADING POLICY

The Board has adopted the NextEra Energy, Inc. Securities Trading Policy (the "Trading Policy"), which specifies policies and procedures that govern the purchase, sale, and other dispositions of the Company's securities by directors, officers and employees that are designed to promote compliance with insider trading laws, rules and regulations, and New York Stock Exchange listing standards. By prohibiting all Company personnel from engaging in prohibited transactions in Company securities for their own account or for the account of any other person or entity, including the Company, the Trading Policy is also designed to promote insider trading compliance by the Company.

COMMON STOCK OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table shows the beneficial ownership of NextEra Energy common stock by the only persons known by the Company to own beneficially more than 5% of the outstanding shares of the Company's common stock based on shares outstanding as of March 25, 2025.

NAME AND ADDRESS OF BENEFICIAL OWNER	AMOUNT AND NATURE OF BENEFICIAL OWNERSHIP	PERCENT OF CLASS
The Vanguard Group(1) 100 Vanguard Blvd. Malvern, PA 19355	206,984,080	10.1%
BlackRock, Inc.(2) 55 East 52nd Street New York, NY 10055	151,490,645	7.4%
State Street Corporation(3) State Street Financial Center One Lincoln Street Boston, MA 02111	116,304,947	5.75%

(1) This information has been derived from a statement on Schedule 13G/A of The Vanguard Group, filed with the Securities and Exchange Commission ("SEC") on February 7, 2025. The Vanguard Group, an investment adviser, reported that, as of January 31, 2025, it had sole dispositive power with respect to 196,700,056 shares reported as beneficially owned, shared dispositive power with respect to 10,284,024 shares reported as beneficially owned, shared voting power as to 3,305,941 shares reported as beneficially owned and no shares with sole voting power.

(2) This information has been derived from a statement on Schedule 13G/A of BlackRock, Inc., filed with the SEC on February 13, 2024. As of December 31, 2023, BlackRock, Inc., a parent holding company, reported that it had sole dispositive power with respect to all of the shares reported as beneficially owned and sole voting power as to 138,638,766 of such shares and no shares with shared voting or dispositive power.

(3) This information has been derived from a statement on Schedule 13G/A of State Street Corporation, filed with the SEC on January 29, 2024. As of December 31, 2023, State Street Corporation, a parent holding company, reported that it had shared dispositive power with respect to 116,003,650 shares reported as beneficially owned, shared voting power with respect to 76,368,218 shares reported as beneficially owned and no sole voting or dispositive power.

The table below shows the number of shares of NextEra Energy common stock beneficially owned as of March 25, 2025 by each of NextEra Energy's directors and NEOs and by all directors, director nominees and executive officers as a group. As of March 25, 2025, all directors, director nominees and executive officers as a group beneficially owned less than 1% of NextEra Energy common stock. No shares are pledged as security.

	COMMON STOCK BENEFICIALLY OWNED			
NAME	SHARES OWNED[1]	SHARES WHICH MAY BE ACQUIRED WITHIN 60 DAYS[2]	TOTAL SHARES BENEFICIALLY OWNED[3]	PHANTOM/ DEFERRED SHARES[4]
Nicole S. Arnaboldi	8,501	—	8,501	14,797
Brian W. Bolster	41,091	—	41,091	272
James L. Camaren	164,320	—	164,320	33,440
Terrell Kirk Crews II	59,111	87,726	146,837	5,546
Naren K. Gursahaney	25,392	—	25,392	21,351
Kirk S. Hachigian	96,225	—	96,225	—
Maria G. Henry	6,930	—	6,930	—
John W. Ketchum	317,124	961,184	1,278,308	28,121
Rebecca J. Kujawa	204,136	374,126	578,262	9,071
Amy B. Lane	24,752	—	24,752	26,393
Geoffrey S. Martha	3,870	—	3,870	—
Armando Pimentel, Jr.	173,110	541,552	714,662	2,226
David L. Porges	43,527	—	43,527	14,258
Charles E. Sieving	230,807	245,211	476,018	34,382
Dev Stahlkopf	7,490	—	7,490	—
John A. Stall	16,534	—	16,534	—
Darryl L. Wilson	21,037	—	21,037	1,029
All directors, director nominees and executive officers as a group (23 persons)	1,700,439	2,461,109	4,161,548	205,314

(1) Includes shares of restricted stock (performance-based for executive officers) for Messrs. Ketchum 10,428, Bolster 37,554, Pimentel 38,670, Sieving 10,670 and Crews 8,055, Mrs. Kujawa 27,585 and Mr. Camaren 12,800, and a total of 228,797 shares of restricted stock for all directors and executive officers as a group. The holders of such shares of restricted stock have voting power, but not dispositive power.

(2) Includes, for executive officers, shares which may be acquired as of or within 60 days after March 25, 2025, upon the exercise of stock options and, for directors, shares payable under the Company's Deferred Compensation Plan, amended and restated effective January 1, 2003 (the "Frozen Deferred Compensation Plan") or the NextEra Energy, Inc. Deferred Compensation Plan effective January 1, 2005, as amended and restated through February 11, 2016, as amended (the "Successor Deferred Compensation Plan"), the receipt of which has been deferred until the first day of the month after termination of service as a Board member. The Frozen Deferred Compensation Plan and the Successor Deferred Compensation Plan are collectively referred to as the "Deferred Compensation Plan."

(3) Represents the total number of shares listed under the columns "Shares Owned" and "Shares Which May Be Acquired Within 60 Days." Under SEC rules, beneficial ownership as of any date includes any shares as to which a person, directly or indirectly, has or shares voting power or dispositive power and also any shares as to which a person has the right to acquire such voting or dispositive power as of or within 60 days after such date through the exercise of any stock option or other right.

(4) Includes phantom shares under the FPL Group, Inc. Supplemental Executive Retirement Plan, amended and restated effective April 1, 1997 (the "Frozen SERP"), and the NextEra Energy, Inc. (f/k/a FPL Group, Inc.) Supplemental Executive Retirement Plan, amended and restated effective January 1, 2005 (the "Restated SERP"). The Frozen SERP and the Restated SERP are collectively referred to as the "SERP."

Corporate Governance and Board Matters

LETTER FROM THE LEAD DIRECTOR

Dear fellow Shareholders,

As the new Lead Director of NextEra Energy, I am proud to represent and serve our independent Directors with our Chairman and CEO John Ketchum.

NextEra Energy is one of the largest electric power and energy infrastructure companies in North America. Our proven track record of delivering strong financial and operational performance begins with our foundation of sound corporate governance and oversight. Our Board follows a rigorous and regularly reviewed set of policies, and its committees are led by talented committee chairs. Each director brings a unique background, a broad range of skills and specialized experience. Together, the Board has brought diverse perspectives to management in leading NextEra Energy to successful results and delivering long-term value for shareholders and other stakeholders alike.

One of our annual initiatives is the shareholder outreach program, which has included participation by our Lead Director beginning in 2023. We believe this engagement with the participation of our Lead Director strengthens our relationships with key decision-makers within institutional investors, and we are committed to continuing this valuable program. In response to shareholder feedback received during our most recent meetings, we implemented the following three important refinements to our corporate governance practices.

1. Board Matrix

We have expanded a detailed chart to easily assess the Board's competencies, along with descriptions of how each competency relates to NextEra Energy's business. We have also included infographics reflecting the director profile and Board composition.

2. Governance Disclosure

We have updated information about our latest governance practices regarding director time commitments and Board oversight of environmental and social risks, and we plan to continue making improvements to enhance the efficacy of our communications with shareholders.

3. Cybersecurity and AI Oversight

Our full Board maintains responsibility for oversight of cybersecurity risks and opportunities, while in 2025, the Audit Committee assumed responsibility for oversight of AI-related risks.

During our meetings, shareholders expressed support for our Board transparency, record of recent Board refreshment, ongoing director succession planning, focus on technology and direct participation in corporate risk mitigation assessments. Board structure and governance were recurring topics, with positive feedback on our efforts to communicate our initiatives with investors through our shareholder outreach program.

We are committed to maintaining strong stakeholder relationships and delivering long-term value by incorporating shareholder feedback into our business practices, and we believe our shareholder outreach program reflects that. Your input is vital to our continued success.

Thank you for your engagement with NextEra Energy during this exciting time for the Company's continued growth trajectory.

Warm regards,

Amy B. Lane

CORPORATE GOVERNANCE PRINCIPLES & GUIDELINES/CODE OF ETHICS

The Board has adopted the Governance Guidelines that set forth expectations for directors, director independence standards, Board committee structure and functions and other policies for the Company's governance. NextEra Energy has adopted a Code of Business Conduct & Ethics applicable to all representatives of NextEra Energy and its subsidiaries, including directors, officers and employees, as well as a Code of Ethics for Senior Executive and Financial Officers ("Senior Code"), which applies to certain senior executive officers. These documents are available on the Company's website at www.investor.nexteraenergy.com/corporate-governance. Any amendments or waivers of the Senior Code will be disclosed at this website address.

In October 2024, the Board amended the Governance Guidelines to expressly address director time commitments. The Governance Guidelines provides in relevant part as follows:

> **"Serving on the Board requires significant time and attention. As a result, the Governance & Nominating Committee will annually review each Director's various time commitments, including the Director's primary occupation, service on public company boards and committee memberships, and leadership positions on such boards, as well as service with private company boards and non-profit organizations."**

AUDIT COMMITTEE CHARTER

In February 2025, the Audit Committee Charter was amended in order to assign risk oversight with respect to the Company's use of AI to the Audit Committee. At least annually, the Audit Committee is responsible for discussing with management, the Company's risk oversight with respect to AI as well as emerging AI developments.

GOVERNANCE & NOMINATING COMMITTEE CHARTER

In May 2024, the Governance & Nominating Committee Charter was amended to provide that the Governance & Nominating Committee will oversee material risks that are environmental or social in nature, monitor the Company's sustainability efforts and initiatives, including matters relating to climate change, review the Company's environmental, social and governance ("ESG") framework, and evaluate ESG trends and developments as they relate to the Company's business activities.

DIRECTOR INDEPENDENCE

The Board conducts an annual review regarding the independence from the Company's management of each of its members and, in addition, assesses the independence of any new member at the time that the new member is considered for appointment or nomination for election to the Board. In assessing independence, the Board considers all relevant facts and circumstances and the standards established by the NYSE and also set forth or referred to in the Governance Guidelines. The NYSE standards and the Governance Guidelines require that NextEra Energy have a majority of independent directors and that the Board must affirmatively determine that each director has no material relationship with the Company in order to determine that the director is independent. Material relationships for this purpose may include commercial, industrial, banking, consulting, legal, accounting, charitable and familial relationships, among others.

Based on its review, the Board determined that Nicole S. Arnaboldi, James L. Camaren, Naren K. Gursahaney, Kirk S. Hachigian, Maria G. Henry, Amy B. Lane, Geoffrey S. Martha, David L. Porges, Dev Stahlkopf, John A. Stall and Darryl L. Wilson, constituting all 11 non-employee directors, are independent under the NYSE standards and the Governance Guidelines.

In determining that Mr. Camaren is independent, the Board considered that a NextEra Energy subsidiary has employed Mr. Camaren's son-in-law since 2021 in a non-executive business role, for total compensation in 2024 of approximately $215,000.

BOARD LEADERSHIP STRUCTURE

The Board believes that the decision as to who should serve as chairman and as CEO and whether the offices should be combined or separate is properly the responsibility of the Board to be exercised from time to time in appropriate consideration of the Company's then-existing characteristics or circumstances. In view of the Company's operating record, including its role as a national leader in renewable energy generation, and the operational and financial opportunities and challenges faced by the Company, the Board's judgment is that the functioning of the Board is generally best served by maintaining a structure of having one individual serve as both chairman and CEO. The Board believes that having a single person acting in the capacities of chairman and CEO promotes unified leadership and direction for the Board and executive management and allows for a single, clear focus for the chain of command to execute the Company's strategic initiatives and business plans and to address its challenges. However, in certain circumstances, such as the transition from one CEO to another, the Board believes that it may be appropriate for the roles of the CEO and the chairman to be separated.

The Board has an independent Lead Director selected by and from the independent directors (with strong consideration given to present and past committee chairs). The Lead Director serves a two-year term commencing on the date of the Company's annual meeting of shareholders. Unless the independent directors determine otherwise due to particular circumstances, no director will serve as the Lead Director for more than one two-year term on a consecutive basis. Amy B. Lane currently serves as the Lead Director, having been appointed initially in May 2024. While Ms. Lane has reached retirement age, the Governance & Nominating Committee recommended, and the Board unanimously approved, extending the retirement date for Ms. Lane and nominating her for election at the 2025 annual meeting. In reaching this decision, the Governance & Nominating Committee and the Board considered the high number of director retirements and new members of the Board who have joined in recent years, as well as the value for the Board in retaining Ms. Lane, who brings important experience and knowledge about the history and strategy of the Company. The Governance & Nominating Committee and the Board also considered Ms. Lane's extensive financial, leadership and managerial skills, among other attributes. Furthermore, Ms. Lane has served the Company and the Board extremely well in the role of Lead Director and in other leadership roles on the Board.

The Lead Director has the following duties and authorities:

- act, on a non-exclusive basis, as liaison between the independent directors and the chairman;
- approve the Board agenda and information sent to the Board;
- preside at Board meetings in the absence of the chairman and chair executive sessions of the non-management directors;
- approve meeting schedules to assure that there is sufficient time for discussion of all agenda items;
- call executive sessions of the independent directors;
- if requested by major shareholders, be available, when appropriate, for consultation and direct communication consistent with the Company's policies regarding communications with shareholders;
- communicate Board member feedback to the CEO; and
- have such other duties as may from time to time be assigned by the Board.

The Board believes that having an independent Lead Director, regular Board and committee executive sessions, a substantial majority of independent directors and the corporate governance structures and processes described in this proxy statement allow the Board to maintain effective oversight of management.

BOARD ROLE IN RISK OVERSIGHT

The Board discharges its risk oversight responsibilities primarily through its committees. The Board exercises its role in risk oversight in a variety of ways, including the following:

AUDIT COMMITTEE	» Oversees the integrity of the Company's financial statements, the independent auditor's qualifications and independence, the performance of the Company's internal audit function and the Company's accounting and financial reporting processes » Oversees compliance with legal and regulatory requirements » Discusses with management the Company's policies with respect to risk assessment and risk management » Reviews and discusses the Company's major financial risk exposures and the steps management has taken to monitor and control those exposures » Ensures that risks identified from time to time as major risks are reviewed by the Board or a Board committee » Discuss with management, at least annually, the Company's risk oversight with respect to AI and emerging AI developments
FINANCE & INVESTMENT COMMITTEE	» Reviews and monitors the Company's financing plans » Reviews and makes recommendations regarding the Company's dividend policy » Reviews risk management activities and exposures related to the Company's energy trading and marketing operations » Reviews the Company's major insurance lines » Oversees the risks associated with financing strategy, financial policies and the use of financial instruments, including derivatives
NUCLEAR COMMITTEE	» Reviews the safety, reliability and quality of nuclear operations » Reviews reports issued by external oversight groups » Reviews the Company's long-term strategies and plans related to its nuclear operations
COMPENSATION COMMITTEE	» Oversees compensation-related risks, including annually reviewing management's assessment of risks related to employee compensation programs » Oversees the compensation risk mitigation practices and controls that the Company has in place
GOVERNANCE & NOMINATING COMMITTEE	» Oversees Board composition and refreshment » Annual review of political contributions and trade association memberships » Provides political engagement oversight » Makes recommendations to the Board on the business of the Annual Meeting of Shareholders » Oversees material environmental or social risks

In May 2024, Mr. Crews was appointed executive vice president, chief risk officer and together with other members of the Company's senior management team, oversees the execution and monitoring of the Company's risk management policies and procedures. NextEra Energy's management maintains a number of risk oversight committees that assess operational and financial risks throughout the Company. NextEra Energy also has a Corporate Risk Management Committee, composed of senior executives, that assesses the Company's strategic risks and the strategies employed to mitigate those risks. The Board committees discussed above meet periodically with the Company's senior management team to review the Company's risk management practices and key findings.

BOARD EVALUATIONS

Each year the Board engages in a self-evaluation process which is conducted by the Governance & Nominating Committee. Members of the Board are surveyed to assess the effectiveness of the Board's membership and oversight processes and to solicit input from members of the Board for improvements to the Board's functions. With the input of the Governance & Nominating Committee, recommendations from Board members are incorporated into Board processes and Board agenda topics. This annual self-evaluation process ensures that the Board periodically considers improvements to Board processes and procedures.

DIRECTOR MEETINGS AND ATTENDANCE

The Board and its committees meet on a regular schedule and hold special meetings from time to time. Executive sessions of the independent directors are scheduled in the agenda for each regularly scheduled Board meeting. The Board met six times in 2024. Each current director attended 100% of the total number of Board meetings and meetings of the committees on which he or she served during 2024. Absent circumstances that cause a director to be unable to attend the Board meeting held in conjunction with the annual meeting of shareholders, Board members are required to attend the annual meeting of shareholders. All 11 then-current directors attended the 2024 annual meeting of shareholders.

BOARD COMMITTEES

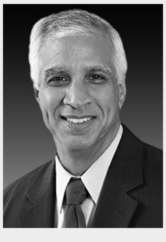
The standing committees of the Board are:

- The Audit Committee
- The Compensation Committee
- The Governance & Nominating Committee
- The Finance & Investment Committee
- The Nuclear Committee
- The Executive Committee

The committees regularly report their activities and actions to the full Board, generally at the next Board meeting following the committee meeting. Executive sessions are held after each regularly scheduled committee meeting (other than quarterly earnings review meetings of the Audit Committee) and are chaired by the committee chairs. Each of the committees operates under a charter approved by the Board and each committee (other than the Executive Committee) conducts an annual self-evaluation of its performance. Current copies of the committee charters are available on the Company's website at www.investor.nexteraenergy.com/corporate-governance. The current membership and primary functions of the committees are described below.

AUDIT COMMITTEE

Meetings in 2024: 8



Members

- **Naren K. Gursahaney** (Chair)
- Nicole S. Arnaboldi
- Maria G. Henry
- Dev Stahlkopf
- Darryl L. Wilson

Qualifications

- All members are independent and financially literate under applicable NYSE and SEC requirements
- Mr. Gursahaney is an audit committee financial expert under the definition provided by the SEC

Primary Responsibilities

- Appoints the Company's independent registered public accounting firm and approves all permitted services to be performed by the firm
- Reviews the independent registered public accounting firm's qualifications, performance and independence
- Approves the engagement of any other registered public accounting firm engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attest services
- Assists the Board in overseeing the integrity of the Company's financial statements and compliance with legal and regulatory requirements
- Assists the Board in overseeing the performance of the Company's internal audit function, the accounting and financial reporting processes of the Company and audits of the Company's financial statements
- Establishes procedures for the receipt, retention and treatment of complaints and concerns received by the Company regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission of concerns regarding questionable accounting or auditing matters

COMPENSATION COMMITTEE

Meetings in 2024: 4

Members

- **Kirk S. Hachigian** (Chair)
- James L. Camaren
- Amy B. Lane
- Dev Stahlkopf
- Darryl L. Wilson

Qualifications

- All members meet the NYSE standards for independence

Primary Responsibilities

- Reviews and approves corporate goals and objectives relevant to the compensation of the CEO and the other executive officers
- Evaluates the performance of the CEO in light of those goals and objectives, approves the compensation of the CEO and the other executive officers, approves any compensation-related agreements for the CEO and the other executive officers and makes recommendations to the Board with respect to the non-employee directors' compensation
- Oversees the preparation of the Compensation Discussion & Analysis section of this proxy statement and approves the Compensation Committee Report
- Reviews the results of the Company's shareholder advisory vote on the compensation of the NEOs, makes recommendations to the Board with respect to incentive compensation plans and other equity-based plans and administers the Company's annual and long-term incentive plans and non-employee directors' stock plan
- Retains and assesses the independence of any outside compensation consultants engaged to assist in the evaluation of executive compensation

GOVERNANCE & NOMINATING COMMITTEE

Meetings in 2024: 4

Members

- **Amy B. Lane** (Chair)
- Naren K. Gursahaney
- Kirk S. Hachigian
- David L. Porges

Qualifications

- All members meet the NYSE standards for independence

Primary Responsibilities

- Reviews the size and composition of the Board, identifies and evaluates potential nominees for election to the Board and recommends candidates for all directorships to be elected by shareholders or appointed by the Board
- Reviews the Governance Guidelines, the Related Person Transactions Policy and the content of the Code of Business Conduct & Ethics and the Senior Code and recommends any proposed changes to the Board
- Oversees the evaluation of the Board
- Makes recommendations to the Board regarding the business of the annual meeting of shareholders, as well as with respect to shareholder proposals that may be considered at the annual meeting
- Annual review of political contributions and trade association memberships

FINANCE & INVESTMENT COMMITTEE

Meetings in 2024: 9

Members

- **David L. Porges** (Chair)
- Nicole S. Arnaboldi
- James L. Camaren
- Maria G. Henry
- Geoffrey S. Martha
- John A. Stall

Qualifications

- All members meet the NYSE standards for independence

Primary Responsibilities

- Reviews and monitors the Company's financing plans
- Reviews and makes recommendations to the Board regarding the Company's dividend policy
- Reviews the Company's risk management activities and exposures related to its energy trading and marketing operations
- Reviews certain proposed capital expenditures
- Reviews the performance of the Company's pension, nuclear decommissioning and other investment funds

NUCLEAR COMMITTEE

Meetings in 2024: 4

Members

- **John A. Stall** (Chair)
- John W. Ketchum

Qualifications

- Mr. Stall meets the NYSE standards for independence

Primary Responsibilities

- Meets with senior members of the Company's nuclear division
- Reviews the operation of the Company's nuclear division and makes reports and recommendations to the Board with respect to such matters
- Reviews, among other matters, the safety, reliability and quality of the Company's nuclear operations and the Company's long-term strategies and plans for its nuclear operations

EXECUTIVE COMMITTEE

Meetings in 2024: 0

Members

- **John W. Ketchum** (Chair)
- Naren K. Gursahaney
- Kirk S. Hachigian
- Amy B. Lane
- David L. Porges

Primary Responsibilities

- Provides an efficient means of considering such matters and taking such actions as may require the attention of the Board or the exercise of the Board's powers or authorities when the Board is not in session

CONSIDERATION OF DIRECTOR NOMINEES

Proxy access shareholder nominees

The Bylaws permit a shareholder, or a group of up to 20 shareholders, owning continuously for at least three years shares of NextEra Energy representing an aggregate of at least 3% of the Company's outstanding shares to nominate and include in the Company's proxy materials director nominees for up to 20% of the current membership of the Board or two directorships, whichever is greater, provided that the shareholder(s) and nominee(s) satisfy the requirements in the Bylaws. Notice of proxy access director nominees for the 2026 annual meeting of shareholders should be addressed to:

The Corporate Secretary
NextEra Energy, Inc.
P.O. Box 14000
700 Universe Boulevard
Juno Beach, Florida 33408-0420

and must be received no earlier than November 2, 2025 and no later than the close of business on December 2, 2025. A copy of the Bylaws containing the complete proxy access requirements is available on NextEra Energy's website at www.investor.nexteraenergy.com/corporate-governance.

Other shareholder nominees

The policy of the Governance & Nominating Committee is to consider properly submitted shareholder nominations of candidates for membership on the Board. Shareholder nominations are reviewed in the same manner as candidates identified by or recommended to the Governance & Nominating Committee. Any shareholder nominations proposed for consideration by the Governance & Nominating Committee should include the nominee's name and qualifications for Board membership, should include all information that the Bylaws require for director nominations and should be addressed to:

The Corporate Secretary
NextEra Energy, Inc.
P.O. Box 14000
700 Universe Boulevard
Juno Beach, Florida 33408-0420

A copy of the Bylaws is available on NextEra Energy's website at www.investor.nexteraenergy.com/corporate-governance. In order for nominations to be timely under the advance notice requirements of the Bylaws for the 2026 annual meeting, they must be received no earlier than January 22, 2026 and no later than February 21, 2026.

COMMUNICATIONS WITH THE BOARD

The Board has established procedures by which shareholders and other interested parties may communicate with the Board, any Board committee, the Lead Director and any one or more of the other directors. Such parties may write to one or more of the directors:

c/o the Chief Legal Officer
NextEra Energy, Inc.
P.O. Box 14000
700 Universe Boulevard
Juno Beach, Florida 33408-0420

or send an e-mail to: boardofdirectors@nexteraenergy.com.

The Board has instructed the Chief Legal Officer to assist the Board in reviewing all written communications to the Board, any Board committee or any director as follows:

- Complaints or similar communications regarding accounting, internal accounting controls or auditing matters will be handled in accordance with the NextEra Energy, Inc. and Subsidiaries Procedures for Receipt, Retention and Treatment of Complaints and Concerns Regarding Accounting, Internal Accounting Controls or Auditing Matters.
- All other legitimate communications related to the duties and responsibilities of the Board or any committee will be promptly forwarded by the Chief Legal Officer to the applicable directors, including, as appropriate under the circumstances, to the chairman of the Board, the Lead Director and/or the appropriate committee chair.
- All other shareholder, customer, vendor, employee and other complaints, concerns and communications will be handled by management with Board involvement as advisable with respect to those matters that management reasonably concludes to be significant.

Communications that are of a personal nature or not related to the duties and responsibilities of the Board, are unduly hostile, threatening, illegal or similarly inappropriate or unsuitable, are conclusory or vague in nature, or are surveys, junk mail, resumes, service or product inquiries or complaints, or business solicitations or advertisements, generally will not be forwarded to any director unless the director otherwise requests or the Chief Legal Officer determines otherwise.

WEBSITE DISCLOSURES

NextEra Energy will disclose the following matters, if such matters should occur, on its website at www.investor.nexteraenergy.com/corporate-governance:

- any contributions by NextEra Energy to tax exempt organizations of which a director of the Company serves as an executive officer exceeding the greater of $1,000,000 or 2% of the organization's revenues in any single fiscal year during the past three fiscal years; and
- any Board determination that service by a member of the Company's Audit Committee on the audit committees of more than three public companies does not impair the ability of that individual to serve effectively on the Company's Audit Committee.

TRANSACTIONS WITH RELATED PERSONS

In 2007, the Board adopted a Related Person Transactions Policy (the "Policy") for the review and approval of related person transactions by the Governance & Nominating Committee. Transactions and series of transactions exceeding $120,000 in any fiscal year involving the Company and in which any related person has a direct or indirect material interest are governed by the Policy ("Related Person Transactions"). Related persons under the Policy are executive officers, directors and nominees for director of NextEra Energy, any beneficial owner of more than 5% of any class of NextEra Energy's voting securities and any immediate family member of any of the foregoing persons ("Related Person").

In considering whether to approve a Related Person Transaction, the Governance & Nominating Committee (or its Chair, to whom authority has been delegated under certain circumstances) considers such factors as it (or the Chair) deems appropriate, which may include:

(1) the Related Person's relationship to NextEra Energy and interest in the transaction;

(2) the material facts of the proposed Related Person Transaction, including the proposed value of such transaction or, in the case of indebtedness, the principal amount that would be involved;

(3) the benefits to NextEra Energy and its shareholders of the Related Person Transaction; and

(4) an assessment of whether the Related Person Transaction is on terms that are comparable to the terms that would be available to an unrelated third party.

The Policy provides for standing approval for certain categories of Related Person Transactions without the need for specific approval by the Governance & Nominating Committee. These categories include:

(1) certain transactions with other companies where the Related Person's only relationship is as an employee (other than an executive officer), partner or principal, if the aggregate amount involved does not exceed the greater of $1,000,000 or 2% of the other company's gross annual revenues in its most recently-completed fiscal year, and

(2) charitable contributions, grants or endowments by NextEra Energy to charitable organizations, foundations or universities with which a Related Person's only relationship is as an employee (other than an executive officer) or a trustee, if the aggregate amount involved does not exceed the lesser of $500,000 or 2% of the charitable organization's total annual receipts in its most recently completed fiscal year.

During 2024, three providers of investment management and administrative services to the Company were beneficial owners of more than 5% of NextEra Energy's outstanding common stock. The nature and value of services provided by these 5% shareholders and their affiliates are described below:

» BlackRock provided investment management services to the NextEra Energy, Inc. Employee Pension Plan and the Employee Retirement Savings Plan, money market fund management services to NextEra Energy subsidiaries, investment services to the decommissioning trust funds for the Duane Arnold and Point Beach nuclear plants and cash management fees; it received fees of approximately $1.1 million for such services in 2024;

» State Street provided investment management and administrative services to the NextEra Energy, Inc. Employee Pension Plan and Employee Retirement Savings Plan and investment services to the decommissioning trust funds for FPL, Duane Arnold, Point Beach and Seabrook nuclear plants; it received fees of approximately $0.7 million for such services in 2024; and

» Vanguard provided investment management and administrative services to the NextEra Energy, Inc. Employee Retirement Savings Plan and received fees of approximately $1.1 million for such services in 2024.

During 2024, the adult son-in-law of Mr. James L. Camaren was employed as a senior financial analyst in the Company's Financial Planning and Analysis Group. His total compensation for 2024 was approximately $215,000 and he was eligible for Company benefits available to all other employees in a similar position.

Audit-Related Matters

AUDIT COMMITTEE REPORT

The Audit Committee submits the following report for 2024:

In accordance with the written Audit Committee Charter, the Audit Committee assists the Board in fulfilling its responsibility for oversight of the quality and integrity of the accounting, auditing and financial reporting practices of the Company. During 2024, the Audit Committee met eight times, including four meetings where, among other things, the Audit Committee discussed the interim financial information contained in each quarterly earnings announcement with the chief financial officer, the chief accounting officer and the independent registered public accounting firm prior to public release.

In discharging its oversight responsibility as to the audit process, the Audit Committee has received the written disclosures and the letter from the independent registered public accounting firm required by applicable requirements of the Public Company Accounting Oversight Board ("PCAOB") regarding the independent registered public accounting firm's communications with the Audit Committee concerning independence and has discussed with the independent registered public accounting firm the firm's independence. The Audit Committee has reviewed any relationships that may affect the objectivity and independence of the independent registered public accounting firm and has satisfied itself as to the firm's independence. The Audit Committee also discussed with management, the internal auditors and the independent registered public accounting firm the quality and adequacy of the Company's internal controls and the internal audit function's organization, responsibilities, resources and staffing. The Audit Committee reviewed with both the independent registered public accounting firm and the internal auditors their audit plans, audit scope and identification of audit risks.

The Audit Committee discussed and reviewed with the independent registered public accounting firm all matters required to be discussed by the applicable PCAOB and SEC requirements and by generally accepted auditing standards, including those required to be discussed by PCAOB Auditing Standard No. 1301, "Communications with Audit Committees," and discussed and reviewed the results of the firm's audit of the financial statements. The Audit Committee also discussed the results of the internal audit examinations.

The Audit Committee reviewed and discussed the audited financial statements of the Company for the year ended December 31, 2024 with management and the independent registered public accounting firm. Management has the responsibility for the preparation of the Company's financial statements and the independent registered public accounting firm has the responsibility for the audit of those statements.

Based on the above-mentioned review and discussions with management and the independent registered public accounting firm, the Audit Committee recommended to the Board that the Company's audited financial statements be included in its Annual Report on Form 10-K for the year ended December 31, 2024, for filing with the SEC.

In addition, and in accordance with the Audit Committee Charter, the Audit Committee reviewed and discussed with management and the independent registered public accounting firm management's internal control report, management's assessment of the internal control structure and procedures of the Company for financial reporting and the independent registered public accounting firm's opinion on the effectiveness of the Company's internal control over financial reporting, all as required to be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2024.

As specified in the Audit Committee Charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements are complete and accurate and in accordance with generally accepted accounting principles. These are the responsibilities of the Company's independent registered public accounting firm and management. In discharging its duties, the Audit Committee has relied on (1) management's representations to us that the financial statements prepared by management have been prepared with integrity and objectivity and in conformity with generally accepted accounting principles and (2) the report of the independent registered public accounting firm with respect to such financial statements.

Respectfully submitted,

THE AUDIT COMMITTEE

Naren K. Gursahaney, *Chair*

Nicole S. Arnaboldi

Maria G. Henry

Dev Stahlkopf

Darryl L. Wilson

FEES PAID TO DELOITTE & TOUCHE

The following table presents fees billed for professional services rendered by Deloitte & Touche, the member firms of Deloitte Touche Tohmatsu Limited, and their respective affiliates, for the fiscal years ended December 31, 2024 and 2023.

DELOITTE & TOUCHE FEES	2024 ($)	2023 ($)
Audit fees(1)	7,651,000	7,423,000
Audit-related fees(2)	4,092,000	3,372,000
Tax fees(3)	775,000	860,000
All other fees(4)	52,000	235,000
Total Fees	12,570,000	11,890,000

(1) Audit fees consist of fees billed for professional services rendered for the audit of NextEra Energy's and FPL's annual consolidated financial statements for the fiscal year, the reviews of the financial statements included in NextEra Energy's and FPL's Quarterly Reports on Form 10-Q filed during the fiscal year, the audit of the effectiveness of internal control over financial reporting, and the issuance of comfort letters and consents.

(2) Audit-related fees consist of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of NextEra Energy's and FPL's consolidated financial statements and are not reported under "Audit Fees." These fees primarily related to audits of subsidiary financial statements, consultations on transactions and financial systems pre-implementation internal control assessments.

(3) Tax fees consist of fees billed for professional services rendered for tax compliance and tax advice and planning. These fees primarily related to research and development tax credit advice and planning services.

(4) All other fees consist of fees for products and services other than the services reported under the other named categories. In 2024, these fees relate to training, in 2023, these fees relate to training and advisory services for Information Technology ("IT") job architecture and skills descriptions.

POLICY ON AUDIT COMMITTEE PRE-APPROVAL OF AUDIT AND NON-AUDIT SERVICES OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

In accordance with the requirements of Sarbanes-Oxley, the Audit Committee Charter and the Audit Committee's pre-approval policy for services provided by the independent registered public accounting firm, all services performed by Deloitte & Touche are approved in advance by the Audit Committee. Permitted services specifically identified in an appendix to the pre-approval policy for which the fee is expected to be $500,000 or less are pre-approved by the Audit Committee each year. This pre-approval allows management to obtain the specified permitted services on an as-needed basis during the year, provided any such services are reviewed with the Audit Committee at its next regularly scheduled meeting. Any permitted service for which the fee is expected to exceed $500,000, or that involves a service not listed on the pre-approval list, must be specifically approved by the Audit Committee prior to commencement of such service. The Audit Committee has delegated to the Chair of the Audit Committee the right to approve audit, audit-related, tax and other services, within certain limitations, between meetings of the Audit Committee, provided any such decision is presented to the Audit Committee at its next regularly scheduled meeting. At each Audit Committee meeting (other than meetings held solely to review earnings materials), the Audit Committee reviews a schedule of services and the estimated fees for those services for which Deloitte & Touche has been engaged since the prior Audit Committee meeting under existing pre-approvals. In 2024 and 2023, no services provided to NextEra Energy or FPL by Deloitte & Touche were approved by the Audit Committee after services were rendered pursuant to Rule 2-01(c)(7)(i)(C) of the SEC's Regulation S-X (which provides a waiver of the otherwise applicable pre-approval requirement under certain conditions).

The Audit Committee has determined that the non-audit services provided by Deloitte & Touche during 2024 and 2023 were compatible with maintaining that firm's independence.

Executive Compensation

COMPENSATION DISCUSSION & ANALYSIS

This Compensation Discussion & Analysis (also referred to as "CD&A") explains our 2024 executive compensation program for our NEOs. Our executive compensation program for NEOs generally applies to our Company's other executive officers, as well. Please read this CD&A together with the tables and related narrative about executive compensation which follow.

CD&A CONTENTS

Named executive officers

Below are our NEOs during 2024 whose compensation is described in this Compensation Discussion & Analysis.

NEOS AND TITLES(1)

JOHN W. KETCHUM
Chairman, President and Chief Executive Officer, NextEra Energy and Chairman, FPL

BRIAN W. BOLSTER
Executive Vice President, Finance and Chief Financial Officer, NextEra Energy and FPL

REBECCA J. KUJAWA
President and Chief Executive Officer, NextEra Energy Resources

ARMANDO PIMENTEL, JR.
President and Chief Executive Officer, FPL

CHARLES E. SIEVING
Executive Vice President, Chief Legal, Environmental and Federal Regulatory Affairs Officer, NextEra Energy and Executive Vice President, FPL

TERREL KIRK CREWS II
Executive Vice President, Chief Risk Officer, NextEra Energy

Executive Summary

Delivering for shareholders, customers and community to position the organization for the future

2024 was another pivotal year for the Company as we delivered strong performance across a spectrum of factors, both financial and non-financial. The execution on these key pillars contributed to both near and longer-term value for stakeholders.

For the full year 2024, NextEra Energy reported net income attributable to NextEra Energy on a GAAP basis of $6.946 billion, or $3.37 per share. We also achieved company-record adjusted earnings of $7.063 billion and adjusted EPS of $3.43. Moreover, continued adjusted EPS growth and strong adjusted ROE for 2024 improved our three-year adjusted EPS growth and adjusted ROE profiles, as shown below.

(1) Effective May 6, 2024, Mr. Bolster was appointed executive vice president, finance and chief financial officer, NextEra Energy and FPL, and Mr. Crews was appointed executive vice president, chief risk officer, NextEra Energy. Mr. Crews previously served as executive vice president, finance and chief financial officer of NextEra Energy and FPL. Mrs. Kujawa has retired from her position as president and chief executive officer of NextEra Energy Resources, Mr. Bolster has been appointed president and chief executive officer of NextEra Energy Resources, and Michael Dunne has been appointed executive vice president, finance and chief financial officer, NextEra Energy and FPL; all effective May 22, 2025. Mr. Dunne, age 49, has served as treasurer of NextEra Energy and FPL and assistant secretary of NextEra Energy since January 2023. He served as vice president, finance of NextEra Energy from April 2022 to December 2022. He also served as treasurer and assistant secretary of XPLR from February 2023 to January 2025 and of XPLR's general partner from December 2022 to February 2025. Before joining NextEra Energy, Mr. Dunne served as managing director, global energy & power investment banking for Bank of America from January 2012 to March 2022.

NET INCOME ATTRIBUTABLE TO NEXTERA ENERGY ON A GAAP BASIS	ADJUSTED EARNINGS*	ADJUSTED EPS*
$6.946 B or $3.37 per share	**$7.063 B** a company record	**$3.43** a company record

* This measure is not a financial measure calculated in accordance with GAAP. See Appendix A to this proxy statement for a reconciliation of this non-GAAP financial measure to the most directly comparable GAAP financial measure.

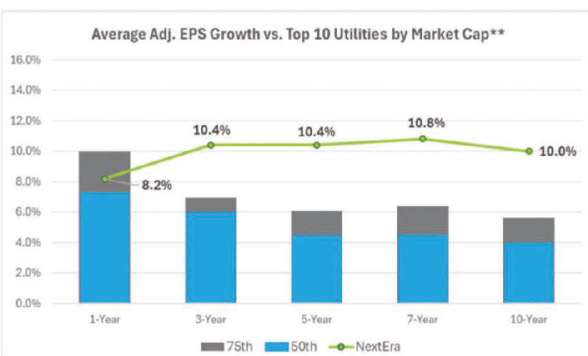
NEXTERA ENERGY KEY METRICS

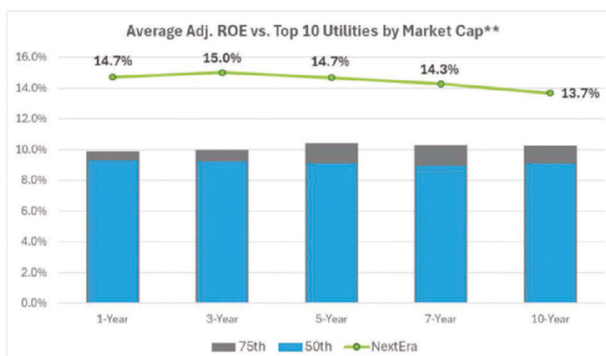
METRIC	DATA	DETAIL
Adjusted EPS Growth (1-year)*	8.2%	2023-2024 YoY Growth
Adjusted EPS Growth (3-year)*	10.4%	2022-2024 Average
Adjusted ROE (1-year)*	14.7%	2024 Return on Equity
Adjusted ROE (3-year)*	15.0%	2022-2024 Average

Each of these corresponds to performance among the top tricile of our peer group as measured for purposes of our compensation programs. These significant accomplishments came as NextEra Energy also continued to be a leader among the ten largest U.S. utilities (based on market capitalization**) in many financial metrics, including those shown below.

NEXTERA ENERGY RANK VS. TEN LARGEST U.S. UTILITIES BASED ON MARKET CAP**

METRIC	RANK	DETAIL
Adjusted EPS Growth*	#1	3-, 5-, 7- and 10-year
Adjusted ROE*	#1	1-, 3-, 5-, 7- and 10-year





When compared to the ten largest utilities based on market cap**, NextEra Energy's adjusted EPS growth over the last ten years has surpassed the median every year and has exceeded the 75th percentile nine out of the last ten years. In addition, NextEra Energy's adjusted ROE has exceeded the 75th percentile of the top ten largest utilities every year during the last ten years.

* This measure is not a financial measure calculated in accordance with GAAP. See Appendix A to this proxy statement for a reconciliation of this non-GAAP financial measure to the most directly comparable GAAP financial measure. See the 2024 Financial Performance Matrix section on page 48 for more information on how the rankings are determined.

** Market capitalization is as of December 31, 2024 and is for companies included in the S&P 500 Utilities Index during the ten-year period from January 1, 2015 to December 31, 2024 for which there are at least three full and consecutive years of comparable financial data and for companies that entered the index before March 31, 2024; rankings are sourced from FactSet Research Systems Inc.

The Company's outstanding performance in 2024 was realized through its two principal operating businesses, FPL and NextEra Energy Resources.

FPL		NEXTERA ENERGY RESOURCES	
Exceeded top-decile performance in minutes of service unavailability per customer and matched best-ever performance in frequency of momentaries	Delivered best-in-class performance in per-customer O&M expense and exceeded top-decile overall fossil fleet generation availability of 93.6%	Added more than 12 GW of new renewables and storage origination to the backlog, setting a new record	Delivered strong performance in wind development, with approximately 1,374 MW of new wind projects placed in service
J.D. Power recognized FPL for excellent residential customer satisfaction in 2024. FPL scored among the top six large utilities nationally, within the top decile, and second among large utilities within the south region	Investments in smart grid technology enabled FPL to avoid more than 2.7 M customer outages in 2024, avoided nearly 800,000 outages during Hurricanes Debby, Helene and Milton	Delivered strong performance in solar development, with adding approximately 3,740 contracted MW of solar development placed in service	Leader in the U.S. in grid-scale battery storage, adding 809 MW of storage placed in service
In 2024, won the ReliabilityOne® Southeast Region Reliability Award	Filed test year letter in December to initiate its rate proceeding for new rates effective in January 2026	Achieved best-ever and exceeded top-decile OSHA recordable rate with 0.15	Grew adjusted earnings by more than 13% compared to prior year

Delivering long-term value to shareholders

NextEra Energy has delivered superior company performance over multi-year cycles, driven in large part by an enduring executive compensation program that aligns with the Company's strong pay for performance philosophy. Our program incentivizes our executives through the application of both annual and multi-year operational and financial performance measures, as well as through the application of a multi-year relative TSR performance measure. The structure is intended to drive consistent performance over the long-term in an industry such as ours, where large capital investment decisions for infrastructure projects which, if developed well over a generally long development cycle and subsequently operated well year-in and year-out, should provide positive, strong returns over extended periods. The structure also acknowledges the historically longer-term economic cycles inherent in the power industry and the sporadic volatility that the power industry experiences from time-to-time.

NEXTERA ENERGY VS. INDICES	1-YEAR TSR	3-YEAR TSR	5-YEAR TSR	7-YEAR TSR	10-YEAR TSR
NextEra Energy	21.5%	(17.0)%	33.2%	117.2%	248.3%
S&P 500 Utilities Index	23.4%	16.5%	37.7%	81.2%	124.7%
S&P 500 Index	25.0%	29.3%	97.0%	147.7%	242.5%

Although neither the S&P 500 Index nor the S&P 500 Utilities Index are peer groups for the purposes of executive compensation, our Company's performance relative to those indices demonstrates that our executive compensation program is incentivizing management to make decisions that deliver long-term value to shareholders relative to some of the highest-performing companies in the world. Our TSR over the 7-year period was mixed compared to the selected indices, and the 10-year time frame continues to compare favorably to the selected indices, while our 1-, 3- and 5-year TSR results trailed these indices, despite strong performance on ROE and EPS growth.

2024 Compensation Program Outcomes

2024 Annual Incentive

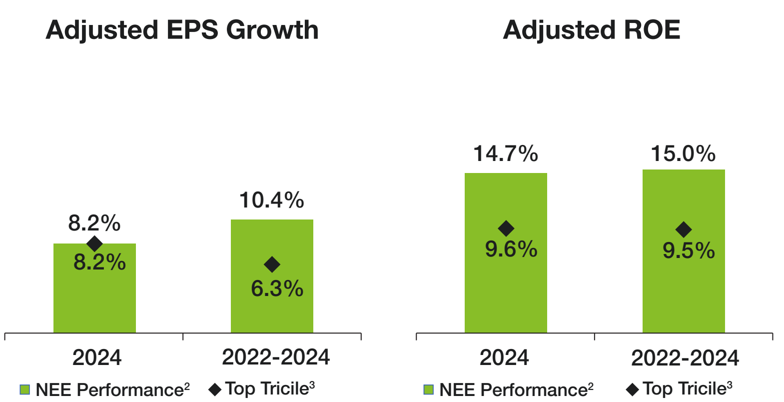
Annual incentive performance is based 50% on financial metrics (Adjusted ROE and Adjusted EPS Growth) as measured against a rigorous performance grid relative to peers as shown on page 49, and 50% based on operational performance metrics primarily established based on industry benchmarks and Company performance. For 2024, NEE performed within the top tricile of both annual incentive financial metrics and performed above-target on most operational metrics. This very strong performance across our business resulted in an above-target annual incentive payout of 181%.

	Metric	Result	Payout Factor
Financial	Adjusted ROE	14.7%	2.00
	Adjusted EPS Growth	8.2%	
Operational	Metrics for FPL and NEER that focus on safety, customer value, reliability, operational excellence, and growth	FPL: 1.65 (50% weighting) NEER: 1.59 (50% weighting)	1.62
		Total annual incentive as percent of target	181%

Long-Term Incentive Payout for 2022-2024 Performance-Share Award Cycle

Performance for the 2022-2024 Performance Share Awards ("PSAs") was measured 80% against a 3-year Adjusted ROE and Adjusted EPS Growth financial matrix, with the remainder evaluated against four key operational measures. Performance is 20 percentage points higher or lower on the basis of 3-year relative TSR performance. The Company performed in the top tricile on each of the financial performance metrics and outperformed across operational metrics, resulting in a potential payout of 198%. However, the Company performed at the 25th percentile on relative TSR, resulting in a downward TSR modifier of -20%, resulting in a payout factor of 80%. This led to an overall payout on the PSAs of 158%.

	Metric	Payout Factor
Financial (80%)	3-year Adjusted ROE and Adjusted EPS Growth	2.00
Operational (20%)	Four measures focused on safety, nuclear industry performance, outage rate, and service reliability	1.90
TSR Modifier (+/- 20%)	Relative 3-year TSR against top ten power companies by market capitalization[1]	80%
	Total 2022-2024 Performance Share Award Payout	158%



1 Market capitalization is as of December 31, 2024; rankings are sourced from FactSet Research Systems Inc.

2 This measure is not a financial measure calculated in accordance with GAAP. See Appendix A to this proxy statement for a reconciliation of this non-GAAP financial measure to the most directly comparable GAAP financial measure. Adjusted ROE is described on page 49.

3 Top tricile of our peer group as measured for the purposes of our compensation programs.

Our commitment to best practices

WHAT WE DO	WHAT WE DO NOT DO
✓ Tie pay to performance; 92% of the CEO's actual direct 2024 compensation was performance-based	✗ No employment agreements with the CEO or other NEOs
✓ Use industry benchmarks when setting operational goals and when reviewing actual performance and generally target top-decile performance as compared to our industry on operational measures	✗ No tax gross-ups of NEO perquisites
✓ Take steps to mitigate undue risk related to compensation, including using a clawback policy, stock ownership and retention requirements and multiple performance metrics; the Compensation Committee conducts an annual comprehensive risk assessment of incentive compensation plans in an effort to confirm that none of the Company's compensation programs creates risks that are reasonably likely to have a material adverse impact on the Company	✗ No single-trigger change in control provisions in agreements entered into since 2021
✓ Have robust stock ownership guidelines	✗ No excise tax gross-up provisions in change in control agreements entered into since 2009
✓ Require executive officers to hold both NEE and XPLR performance-based restricted stock for two years after vesting	✗ No repricing of underwater stock options
✓ Have a minimum full vesting period for stock options and performance-based restricted stock, generally three years	✗ No share recycling under equity compensation plans
✓ Use an independent compensation consultant	✗ No hedging or pledging of company securities by NEOs or directors permitted under securities trading policy
✓ Engage in shareholder outreach and regularly assess the executive compensation program against shareholder input, emerging trends and other factors	✗ No counting of unvested equity toward meeting stock ownership guidelines
✓ Require NEOs to enter into Rule 10b5-1 plans with minimum waiting periods to transact trades in company securities	✗ No guaranteed annual or multi-year bonuses

How the Company's annual incentive plan and long-term incentives support stewardship

In addition to those metrics in our annual incentive plan and our performance shares that emphasize our commitment to environmental protection and stewardship, our executive compensation program also includes goals tied to customer value, employee safety and compliance with environmental regulations, a variety of which have been included as compensation metrics since 2001.

Compensation metrics tied to environmental protection and stewardship include:

CUSTOMER VALUE PROPOSITION

To emphasize the delivery of a sustainable, outstanding customer value proposition, compensation metrics include:

- O&M costs per retail MWh,
- capital expenditures,
- service reliability, and
- customer satisfaction scores.

These metrics are intended to drive the sustainable delivery of:

- low bills,
- high reliability,
- energy solutions, and
- outstanding customer service.

OPERATIONAL PERFORMANCE

Intended to support continued efficient and reliable delivery of energy to our customers.

These metrics include:

- availability metrics across the generation fleets, and
- reliability metrics for the transmission and distribution grid.

SAFETY

Safety is a Company priority because people are our most important asset and safety is a leading indicator of our operational performance.

- The number of OSHA recordable incidents is included to emphasize the Company's focus on a zero-injury workplace and incentivize senior executive leadership on safety issues.

ENVIRONMENTAL EVENTS

To support our commitment to the environment, metrics include:

- achieving zero significant environmental violations across all of our businesses.

Design of our executive compensation program

Compensation elements designed to align with our strategy

> Our executive compensation program is designed to attract, retain, motivate, reward and develop high-quality, high-performing executive leadership whose talent and expertise should increase the prospects of the Company to create and sustain long-term and superior shareholder value relative to our peers.

As discussed in more detail throughout the CD&A, NEO direct compensation has three principal elements: base salary, annual incentive awards and equity compensation.

ELEMENT	HOW IT IS PAID	DESCRIPTION	PERIOD
BASE SALARY	Cash	Fixed amount reflects the responsibilities and day-to-day contributions of the NEOs.	One year
ANNUAL INCENTIVE	Cash	Financial metrics: One-year adjusted EPS growth and adjusted ROE compared to the ten-year average of the companies in the S&P 500 Utilities Index. Operational metrics: FPL and NEER operational goals are primarily established based on industry benchmarks and Company performance.	
EQUITY COMPENSATION	Performance shares	Granted for three-year performance periods to drive intermediate and long-term results. Payouts of performance shares are based on two distinct measurements: **1.** three-year adjusted EPS growth and adjusted ROE relative to the ten-year average of the companies in the S&P 500 Utilities Index, and **2.** the average of annual performance on core operational performance measures relative to industry peers for each of three consecutive years. Award payouts are modified by ± 20% based on our three-year TSR relative to the top ten power companies by market capitalization (a subset of the S&P 500 Utilities Index).	Vest after three years
	Performance-based restricted stock	Vest only if the Company achieves a specified annual adjusted earnings goal each year.	Vest ratably over three years
	Performance-based restricted XPLR common units	Vest only if XPLR achieves a specified annual adjusted EBITDA goal each year.	
	Non-qualified stock options	Granted with a ten-year term and delivering value to executives only if the Company's stock price at exercise exceeds the stock price on the grant date of the award.	

The Compensation Committee believes these core elements align with the fundamental objective of our compensation program to create superior shareholder value.

Key principles and practices of our compensation program align executive and shareholder interests. Selected highlights of our 2024 program are:

1. We set target total direct compensation opportunity and pay mix to support the goals of shareholder value creation and executive retention.

» Each NEO's 2024 target compensation opportunity was set with reference to two benchmarking groups: energy services and general industry. These groups represent the broad, competitive labor market from which we recruit and compete for executive talent. This target opportunity is allocated over several forms of compensation, the mix of which supports shareholder value creation and executive retention.

2. We link NEO financial success to shareholder value creation.

» All NEOs' 2024 compensation included a significant element of equity compensation, supported by:

- robust stock ownership guidelines,
- performance hurdles,
- vesting schedules, and
- the potential for clawback.

3. We value and review our performance relative to our competitors and peers whenever possible, rather than relative to arbitrary goals.

» The basic principle underlying the linkage between our financial and operational performance and executive compensation is that superior relative performance will result in above-target compensation, while inferior relative performance will generally result in below-target compensation. Wherever comparable information was available, our 2024 financial and operational performance was measured relative to industry performance.

4. We select compensation metrics linked to our long-term success; our principal financial metrics in 2024 were adjusted ROE and adjusted EPS growth.

» Our 2024 plan measures adjusted ROE and adjusted EPS growth compared to the S&P 500 Utilities Index over a ten-year period. The Compensation Committee believes these financial metrics:

- are objective,
- require superior performance,
- are aligned with creating shareholder value and
- encourage stretch goals.

The Compensation Committee believes a ten-year period is appropriate due to the historically longer-term economic cycles inherent in the power industry and the sporadic volatility the power industry experiences from time-to-time. The Compensation Committee accordingly believes a ten-year period reduces the likelihood, in any given year, that inappropriate metrics will be established as a result of short-term industry anomalies.

Our target pay mix is heavily weighted toward performance

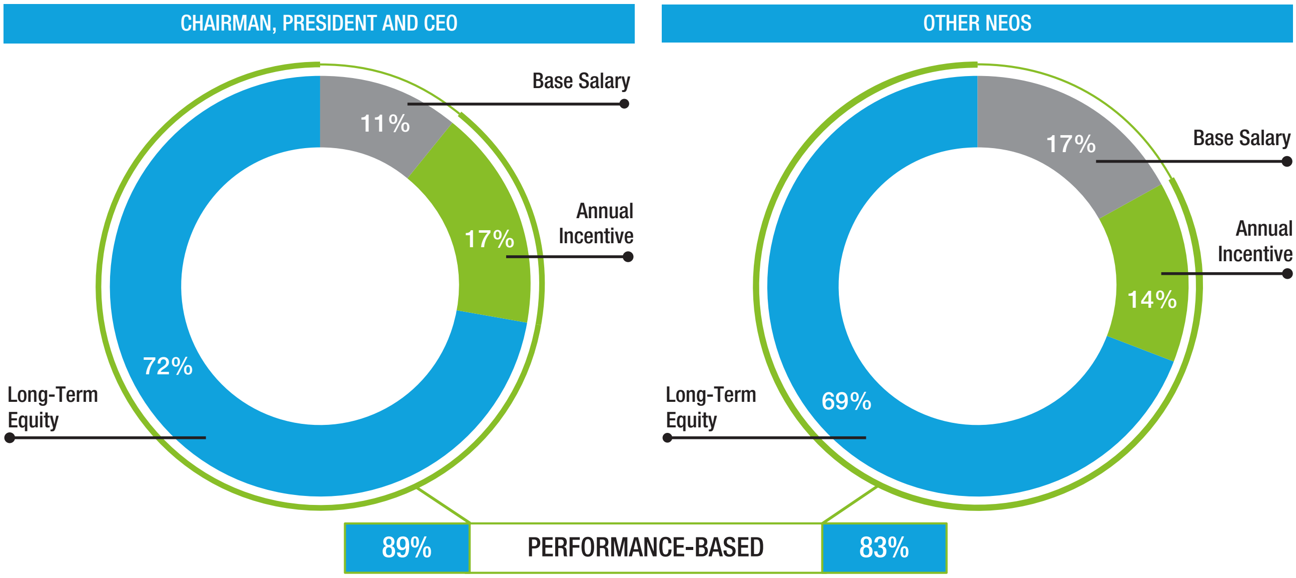
The Compensation Committee believes a significant portion of each NEO's total direct compensation opportunity should be performance-based, reflecting both upside and downside potential.

When determining the proportion of total compensation of each compensation element in 2024, the Compensation Committee reviewed current market practices and industry trends, taking into consideration the Company's preference for emphasizing performance-based compensation and de-emphasizing fixed compensation.

In determining performance-based compensation for 2024, the Compensation Committee sought to focus the efforts of the NEOs on a balance of short-term, intermediate-term and long-term goals. In addition, the Compensation Committee considered the NEOs' perception of the relative values of the various elements of compensation and sought input from the CEO and the Compensation Consultant (as defined below).

Approximately 89% of our CEO's target pay is performance-based, which creates strong alignment with the interests of our shareholders and reinforces our pay for performance culture.

TOTAL DIRECT COMPENSATION — TARGET PAY MIX



Our Incentive Plans Utilize Rigorous Targets

The Compensation Committee endeavors to set rigorous targets for our annual and long-term incentive plans in the context of company expectations for the year, relevant industry benchmarks, stage of our development cycles, and other relevant factors. Given year-over-year variability in our operating environment, certain targets may be set higher, at, or lower than prior year performance, and comparing such metrics year-over-year does not reflect the full scope of factors that may influence performance and ultimate difficulty in achieving these targets. The Compensation Committee follows a thorough process to set targets considering industry benchmarks and internal historical Company performance.

How we make compensation decisions

Compensation Committee role and processes; Role of external consultant

The Compensation Committee plans its agendas to ensure a thorough and thoughtful decision process. Typically, information regarding strategic decisions with respect to the NEOs is presented at one meeting to the Compensation Committee, which makes its decision at a subsequent meeting. This allows time for follow-up questions from Compensation Committee members in advance of the final decision. The Compensation Committee may not delegate its authority.

The Compensation Committee had an executive session at the end of each of its 2024 meetings, during which no executive officers were present. During the appropriate executive sessions, the Compensation Committee:

- evaluated the performance of the chairman and CEO,
- discussed and approved the compensation of the chairman and CEO,
- met with the Compensation Consultant, and
- discussed and considered such other matters as it deemed appropriate including succession planning for key executive positions.

During 2024, the Compensation Committee engaged Frederic W. Cook & Co., Inc. (“FW Cook” or “Compensation Consultant”), an independent executive compensation consulting firm which performed no other services for NextEra Energy or its affiliates, to provide advice and counsel to the Compensation Committee from time-to-time.

In 2024, the Compensation Consultant participated in all Compensation Committee meetings. In accordance with its engagement letter, during the 2024 executive compensation cycle, FW Cook provided the Compensation Committee and the Company with analyses and advice on topics such as pay competitiveness and executive compensation program plan design. FW Cook also benchmarked and discussed with the Compensation Committee its recommendation with respect to non-employee director compensation. The Compensation Consultant also monitored current and emerging market trends and reported to the Compensation Committee on such trends and their impact on the Company's compensation practices. In 2024, the Compensation Committee also assessed the independence of FW Cook in accordance with SEC rules and concluded FW Cook's work for the Compensation Committee did not raise any conflicts of interest.

Compensation resources

The Compensation Committee used its business judgment to set each NEO's target total direct compensation opportunity for 2024 and each compensation element. The Compensation Committee based its determination on its integrated assessment of a series of factors, including:

- competitive alternatives,
- individual and team contribution and performance,
- corporate performance,
- complexity and importance of the role and responsibilities,
- experience,
- leadership and growth potential, and
- the relationship of the NEO's pay to the pay of NextEra Energy's other executive officers.

There are no material differences among NEOs with respect to the application of NextEra Energy's compensation policies or the way in which total compensation opportunity is determined.

The Compensation Committee primarily used the following resources to aid in its determination of the 2024 target total direct compensation opportunity for each NEO.

MARKET COMPARISONS/PEER GROUP

When establishing each NEO's target total direct compensation opportunity for 2024, the Compensation Committee considered the competitive market for comparable executives and compensation opportunities provided by similar companies. Competition for executive talent primarily affects the aggregate level of the target total direct compensation opportunity available to the NEOs.

> The Compensation Committee believes it is critical to the Company's long-term performance to offer its executive officers compensation opportunities broadly commensurate with their competitive alternatives.

The Company obtained market comparison information for all NEOs from publicly-available peer group information and market survey data. The Company's peer group is composed of a set of companies from the energy services industry and a set of companies from the general industry. These companies were selected by the Compensation Committee with input from executive officers (including the CEO) and the Compensation Consultant. The Compensation Committee believes the use of companies from both the energy services industry and the general industry was appropriate because the Company's executive officers come from both within and outside the Company's industry. The Compensation Committee believes their opportunities for alternative employment are not limited to other energy or utility companies.

For 2024, the Compensation Committee conducted a review of the then-existing 2023 peer group based on the following criteria:

SELECTION CRITERIA

ENERGY SERVICES INDUSTRY

- Publicly traded company with a strong United States domestic presence
- Classified with a Standard Industrial Classification ("SIC") code similar to the Company's SIC code
- Annual revenue greater than $5 B
- A potential source of executive talent

GENERAL INDUSTRY

- Publicly traded company with a strong United States domestic presence
- Member of the S&P 500
- Considered highly reputable and highly regarded for operational excellence, product/service leadership or customer experience
- Sustained revenues typically between 50% and 250% of the Company's revenues
- Consistently high performing
- Heavily industrialized, highly regulated or a producer of consumer staples
- Operates in an industry which may be potential sources of executive talent
- No unusual executive pay arrangements
- Contribute to diversity of industry representation in this segment of the peer group

Based on its review, the Compensation Committee approved for 2024 the same peer group that was approved for 2023, since all energy services industry and general industry companies continued to meet the selection criteria. The Compensation Committee believes the peer group is appropriately aligned with industries in which the Company competes for talent and the Company's business in terms of market capitalization and scope. The 2024 comparator groups are as follows:

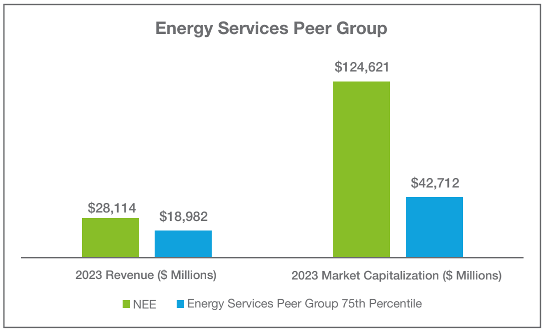
ENERGY SERVICES INDUSTRY (N=13)

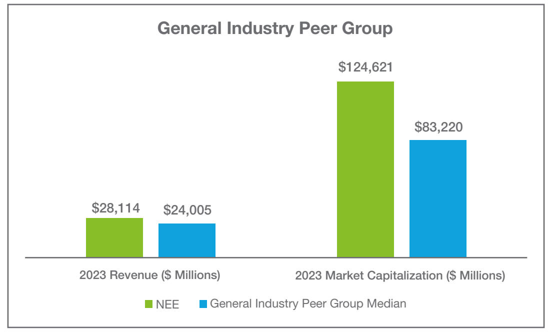
- American Electric Power Company, Inc.
- Consolidated Edison, Inc.
- Dominion Energy, Inc.
- Duke Energy Corporation
- Edison International
- Entergy Corporation
- Exelon Corporation
- FirstEnergy Corp.
- PPL Corporation
- Public Service Enterprise Group Incorporated
- Sempra Energy
- The Southern Company
- Xcel Energy Inc.

GENERAL INDUSTRY (N=20)

- 3M Company
- Air Products and Chemicals, Inc.
- Caterpillar Inc.
- CIGNA Corporation
- Danaher Corporation
- Deere & Company
- Devon Energy Corporation
- DuPont De Nemours, Inc.
- Eaton Corporation
- Emerson Electric Co.
- General Dynamics Corporation
- Halliburton Company
- Honeywell International, Inc.
- Illinois Tool Works Inc.
- Marsh & McLennan Companies, Inc.
- Northrop Grumman Corporation
- Schlumberger Limited
- Texas Instruments Incorporated
- Thermo Fisher Scientific, Inc.
- Union Pacific Corporation

A comparison of NextEra Energy's 2023 revenue and market capitalization to FY2023 data for energy services and general industry peer companies illustrates the Company's revenue and market capitalization exceeds the 75th percentile of the energy services group for both revenue and market capitalization and exceeds the medians for the general industry peer group.





Although the Compensation Committee did not target specific total compensation levels relative to industry peers (a so-called "percentile" approach), it generally reviewed peer company data at the 50th percentile for the general industry companies and the 75th percentile for the energy services industry companies. The Compensation Committee believes these levels were appropriate because:

- the Company's 2023 market capitalization was at the 70th percentile and assets were above the 90th percentile of its general industry peer companies and both market capitalization and assets were at the top of its energy services industry peer companies;
- the Company's 2023 market capitalization was more than 60% greater than that of the 2nd largest energy services industry peer company's market capitalization;
- the Company's practice is to make a relatively high portion of each NEO's compensation performance-based as compared to its peers; and
- the Company's operations are more complex, more diverse and of a greater size than those of substantially all of its energy services industry peer companies.

Other resources

WHAT WE USE	HOW WE USE IT
"Tally sheets" and "walk-away charts"	» Provides a check to ensure the Compensation Committee sees the full value of all elements of the NEOs' annual compensation, both as opportunity and as realized, and sees the estimated results of its compensation decisions in the various situations under which employment may terminate
Reviews by the CEO	» Prior to the beginning of the year, the Compensation Committee solicits performance reviews of the other NEOs and executive officers from the CEO for use as an additional input to the Compensation Committee's determination of target total direct compensation opportunity and, after the end of the year, whether or not to use their discretion to adjust annual incentive compensation amounts determined using the formula discussed on page 55

2024 named executive officer compensation

2024 base salary

Generally, salary increases were based on market considerations, the nature and responsibilities of each NEO's respective position, expertise and performance, the competitiveness of each NEO's current pay in relation to their corresponding peer group and the recommendations of the CEO. The Compensation Committee kept all target compensation, including base salaries, flat for 2024 because of the one-year relationship of pay and performance compared to our peers, despite outperformance in previous years. Base salary adjustments are typically effective as of January 1st each year.

CHANGE IN NEO BASE SALARY

NAMED EXECUTIVE OFFICER	2023 BASE SALARY ($)	2024 BASE SALARY ($)	PERCENTAGE INCREASE %
John W. Ketchum	1,575,000	1,575,000	0%
Brian W. Bolster(1)	—	950,000	—
Rebecca J. Kujawa	1,100,000	1,100,000	0%
Armando Pimentel, Jr.	1,000,000	1,000,000	0%
Charles E. Sieving	1,274,000	1,274,000	0%
Terrell Kirk Crews II	730,300	730,300	0%

(1) Mr. Bolster was not a named executive officer in 2023.

2024 annual performance-based compensation

Annual Incentive Plan goals are established to incentivize superior performance relative to industry peers. A majority of these goals are based on industry benchmarks and payouts under the Annual Incentive Plan are generally based on Company performance in the relevant period.

Prior to 2024, the Compensation Committee established financial and operational performance goals under the Annual Incentive Plan in the following categories:

TYPE OF 2024 PERFORMANCE GOALS	HOW WE ESTABLISHED AND USED THE 2024 PERFORMANCE GOALS
FINANCIAL	» Based on enduring standards indicative of sustained performance — adjusted EPS growth and adjusted ROE — as compared to the financial performance over the ten-year period ended on December 31, 2024 of the companies included in the S&P 500 Utilities Index. » Higher ratings indicate corporate financial performance superior to industry median and lower ratings indicate corporate financial performance which lags industry median.
OPERATIONAL	» Goals and payout scales are established in advance of the year using available industry benchmarks insofar as possible. » If an industry benchmark is not available, the applicable goal generally is set at a level representing an improvement or a stretch as compared to prior performance. » As a general principle, the Compensation Committee seeks to set operational performance goals at levels that represent excellent performance, superior to the results of typical companies in our industry and require significant effort on the part of the executive team to achieve. » Performance on certain compliance-related goals is scored as either "met" or "not met," while performance against other goals is judged on a sliding scale in comparison to top-decile, top-quartile, median and sub-median performance as compared to the industry.

2024 FINANCIAL PERFORMANCE MATRIX

The financial performance matrix approved by the Compensation Committee for 2024, which is illustrated below, compares the Company's 2024 adjusted EPS growth and adjusted ROE to the actual annual adjusted EPS growth and average adjusted ROE of the companies included in the S&P 500 Utilities Index that entered the index before March 31, 2024 and have at least three consecutive years of comparable financial data, during the ten-year period from January 1, 2015 to December 31, 2024 (estimated for 2024 using actual results for the first three quarters and analysts' estimates for the fourth quarter).

The Compensation Committee believes these financial metrics are "enduring standards," because they:

- are objective,
- require the Company to demonstrate improvement,
- are aligned with how shareholder value is created, and
- encourage management to include stretch goals as part of the annual budget-setting process.

The financial performance matrix is designed to provide relatively greater rewards if the Company outperforms others in its industry on the indexed measures and relatively lower rewards if it does not.

ADJUSTED EPS GROWTH*

The Compensation Committee selected adjusted EPS growth because it provides a more meaningful representation of the Company's fundamental earning power than net income calculated in accordance with GAAP and therefore better aligns the NEOs' motivations with the Company's strategy and with shareholders' long-term interests. In addition, the Compensation Committee believes the use of adjusted EPS growth for this purpose is consistent with the way in which the Company communicates its earnings to analysts and investors.

ADJUSTED ROE*

Adjusted ROE is a long-term value creation metric that aligns the interest of management with those of our shareholders by measuring and rewarding profitability relative to shareholders' investment. The Compensation Committee selected adjusted ROE because it is a gauge of our profitability and how efficiently we generate profits.

The numbers in the following matrix set forth the range of possible ratings for corporate financial performance. A rating of "1" indicates overall corporate financial performance at the industry median, while higher ratings indicate corporate financial performance superior to the industry median, and lower ratings indicate corporate financial performance which lags the industry median.

It is important to recognize the adjusted ROE and adjusted EPS growth amounts set forth in the illustration below reflect actual industry performance on these measures for the ten-year period ended December 31, 2024, and the Company's executive compensation is based, with respect to adjusted ROE and adjusted EPS growth, on the performance delivered by the Company relative to industry performance.

Adj. Return on Equity (ROE)	Top Tricile	9.1%	1.00	1.50	2.00
	Median	8.5%	0.75	1.00	1.50
	Bottom Tricile	7.8%	0.50	0.75	1.00
			3.2%	5.0%	5.8%
			Bottom Tricile	Median	Top Tricile
			Adjusted EPS Growth		

* Adjusted EPS growth and adjusted ROE which are used, among other reasons, to provide industry comparability, are not financial measurements calculated in accordance with GAAP and their definitions may differ among companies. Adjusted EPS growth, as defined by NextEra Energy for purposes of the Annual Incentive Plan, is equal to the Company's adjusted earnings dividend by weighted average diluted shares outstanding. Adjusted earnings, as defined by NextEra Energy for purposes of the Annual Incentive Plan, is the Company's consolidated net income, as reported in the audited annual financial statements as determined in accordance with GAAP, excluding the effects of:

(i) changes in the mark-to-market value of non-qualifying hedges;

(ii) other than temporary impairments on investments;

(iii) extraordinary items;

(iv) non-recurring charges or gains (e.g., restructuring charges and material litigation losses);

(v) discontinued operations;

(vi) regulatory and/or legislative changes and/or changes in accounting principles;

(vii) labor union disruptions; and

(viii) acts of God such as hurricanes.

Adjusted ROE, as defined by NextEra Energy, is equal to the Company's adjusted earnings divided by average common shareholders' equity, adjusted to provide industry comparability, expressed as a percentage.

2024 OPERATIONAL GOALS

Operational goals and payout scales are primarily established based on industry benchmarks and Company performance. As noted previously, management's ability to deliver performance superior to our industry will generally result in above-target compensation, while performance that is inferior to our industry will generally result in below-target compensation.

In that context, FPL's typical performance goals based on industry benchmarks are generally better than the top-quartile performers in its industry and NextEra Energy Resources' performance goals based on earnings growth and profitability are well above utility industry norms (in both cases based on internal reviews of publicly available information and information provided by consultants and industry associations).

The following tables set forth the 2024 operational performance goals and the actual performance achieved against those goals.

FPL					
	INDICATOR	GOAL	ACTUAL	INDICATOR WEIGHT	TOTAL SECTION WEIGHT
Customer Value	O&M costs (plan-adjusted)[1]	$1,275 million[1]	$1,247 million[1] exceeded top decile	35%	50% 
	Capital expenditures (plan-adjusted)[1]	$7,356 million[1]	$8,508 million[1]	15%	
Reliability	Fossil generation availability[2]	top decile performance	exceeded top decile performance	6%	30% 
	Nuclear industry composite performance index[3]	top decile performance	missed goal	6%	
	Service reliability — service unavailability (minutes)	better than top decile (49.0 minutes)	exceeded top decile performance (45.7 minutes)	7%	
	Service reliability — average frequency of customer interruptions	0.62 interruptions per customer per year (better than top decile)	0.49 — exceeded top decile performance	7%	
	Service reliability — average number of momentary interruptions per customer	4.2 momentary interruptions per customer per year	3.3 — exceeded top decile performance	4%	
Operational	Employee safety — OSHA recordables[4] per 200,000 hours	0.33 — top decile	0.51 — approximated top quartile performance	8%	20% 
	Significant environmental violations	0	0	2%	
	Customer satisfaction — residential value surveys	aggressive goal	missed goal	4%	
	Customer satisfaction — business value surveys	aggressive goal	missed goal	4%	
	Performance under FERC and NERC reliability standards[5]	no significant violations	met goal	2%	

(1) Certain of the financial performance indicators used in the Annual Incentive Plan are calculated in a manner consistent with NextEra Energy's planning and budgeting process and how management reviews its performance relative to that plan, and are not, or do not relate directly to, financial measures calculated in accordance with GAAP.

For information about the Company's results of operations for 2024, as presented in accordance with GAAP, investors should review the Company's Annual Report on Form 10-K for the year ended December 31, 2024 and should not rely on any adjusted amounts or non-GAAP financial measures set forth above. The following explains how the plan-adjusted amounts are calculated from NextEra Energy's audited consolidated financial statements:

(a) FPL O&M costs (plan-adjusted) is a measure that includes most but not all O&M expenses and includes certain expenses that are not classified as O&M expenses under GAAP but are reported for state regulatory purposes as O&M expenses;

(b) FPL capital expenditures (plan-adjusted) are presented on an accrual basis, and exclude nuclear fuel payments and certain costs that are not classified as capital expenditures under GAAP in the consolidated statements of cash flows but that are reported for state regulatory purposes as capital expenditures; and

(c) NextEra Energy Resources' earnings (plan-adjusted) exclude:

(i) the mark-to-market effect of non-qualifying hedges;

(ii) other than temporary impairments on investments;

(iii) extraordinary items;

NEXTERA ENERGY RESOURCES					
	INDICATOR	GOAL	ACTUAL	INDICATOR WEIGHT	TOTAL SECTION WEIGHT
FINANCIAL	Earnings (plan-adjusted)[1]	$3,122 million[1]	$3,118 million[1]	25%	52% 
	ROE	14.6%	14.3%	10%	
	Meet budgeted cost goals	$3,023 million	$3,010 million	7%	
	XPLR cash available for distribution	$730 million	missed goal	10%	
OPERATIONAL	Employee safety — OSHA recordables[4] per 200,000 hours	0.33 — top decile	0.15 — beat goal and exceeded top decile performance	3%	18% 
	Significant environmental violations	0	0	2%	
	Nuclear industry composite performance index[3]	top decile performance	beat goal and exceeded top decile performance	5%	
	Equivalent forced outage rate[6]	top decile performance	beat goal and exceeded top decile performance	8%	
GROWTH	Execute approved North American new and repowered wind projects on schedule and on budget	1,700 MW	beat goal	10%	30% 
	Execute approved North American solar and storage projects on schedule and on budget	4,225 MW	beat goal	5%	
	New development or acquisition opportunities within NextEra Energy Resources that receive approval	aggressive goal	beat goal	10%	
	Pre-tax income contribution from all asset optimization, marketing and trading activities, full requirements and retail	aggressive goal	beat goal	5%	

(iv) non-recurring charges or gains (e.g., restructuring charges and material litigation losses);

(v) discontinued operations;

(vi) regulatory and/or legislative changes and/or changes in accounting principles;

(vii) labor union disruptions; and

(viii) acts of God such as hurricanes.

(2) "Fossil generation availability" measures the amount of time during a given period that a power generating unit is available to produce power.

(3) The "nuclear industry composite performance index" referenced is the Institute of Nuclear Power Operations ("INPO") index. INPO promotes the highest levels of safety and reliability in the operation of commercial nuclear power plants by establishing performance objectives, criteria and guidelines for the nuclear power industry and conducting regular detailed evaluations of all nuclear power plants in North America. The INPO index is an 18-month rolling average of a nuclear plant's, and a company's nuclear fleet's, performance against operating performance measures.

(4) "OSHA" is the United States Occupational Safety and Health Administration. An OSHA recordable injury is an occupational injury or illness that requires medical treatment more than simple first aid and must be reported under OSHA regulations.

(5) "FERC" is the Federal Energy Regulatory Commission and "NERC" is the North American Electric Reliability Corporation. The determination of a violation is based on the year in which the penalty is paid, rather than the year in which the violation occurred. No violations in 2024.

(6) "EFOR" is the equivalent forced outage rate and is computed as the hours of unit failure (unplanned outage hours and equivalent unplanned de-rated hours) given as a percentage of the total hours of the availability of an electricity generating unit.

	Operational Performance Metrics	Description/Rationale	FPL Metric	NEER Metric
Customer Value	O&M costs (plan-adjusted)	O&M costs play a crucial role in ensuring the efficient, reliable, and safe operation of our infrastructure while minimizing costs, ensuring customer satisfaction and meeting regulatory requirements. Our best-in-class operations and maintenance costs ensure lower bills for our customers.	x	-
	Capital expenditures (plan-adjusted)	By making strategic capital expenditures, we can deliver sustainable, reliable, efficient service while reducing long-term costs, staying competitive and meeting regulatory requirements.	x	-
Reliability/Operational	Fossil generation availability(2)	High availability rates evidence efficient operations, good management and effective maintenance practices. We set our goal as exceeding the top decile of performance within the 2023 NERC survey; we do not disclose the specific goal as we are unable to share the underlying data as it was acquired through a purchased survey subject to confidentiality and proprietary restrictions.	x	-
	Nuclear industry composite performance index(3)	The “nuclear industry composite performance index” referenced in the INPO index. INPO promotes the highest levels of safety and reliability in the operation of commercial nuclear power plants by establishing performance objectives, criteria and guidelines for the nuclear power industry and conducting regular detailed evaluations of all nuclear power plants in North America. The INPO index is an 18-month rolling average of a nuclear plant’s, and a company’s nuclear fleet’s, performance against operating performance measures. We do not disclose the specific goal as we are unable to share the underlying data as it was acquired through purchased survey subject to confidentiality and proprietary restrictions.	x	x
	Service reliability — service unavailability (minutes)	The amount of downtime where power or other utility service was not provided due to outages or interruptions. We strive to minimize the number of minutes of service unavailability, as high availability rates are critical for customer satisfaction, operational efficiency and regulatory compliance. Our aggressive goal was set as exceeding the top decile performance level, as established by the 2023 Edison Electric Institute (EEI) survey results.	x	-
	Service reliability — average frequency of customer interruptions	Represents how often, on average, a customer experiences an interruption in service during the year. By including this metric, we incentivize management to understand and track the causes of these interruptions, as well as develop strategies to minimize their occurrence, thus improving overall service reliability and customer satisfaction. Our aggressive goal was set as exceeding the top decile performance level, as established by the 2023 Edison Electric Institute (EEI) survey results.	x	-
	Service reliability — average number of momentary interruptions per customer	The average number of momentary interruptions (brief outages of a few seconds to a few minutes) per customer is another measure of service reliability.	x	-

	Operational Performance Metrics	Description/Rationale	FPL Metric	NEER Metric
Reliability/Operational	Employee safety — OSHA recordables per 200,000 hours(4)	OSHA recordables per 200,000 hours is a standardized safety evaluation metric where a lower rate indicates fewer recordable incidents in the workplace, and as a result, a safer work environment. Safety is a leading indicator of our overall operational processes, and this metric is a key performance indicator of our safety practices. Good safety practices can contribute to better operational efficiency and resource utilization. Our aggressive goal was set as exceeding the top decile performance level, as established by the 2023 Edison Electric Institute (EEI) survey results.	x	x
	Significant environmental violations	We focus on eliminating significant environmental violations by setting the annual goal at zero such incidents — this demonstrates our commitment to environmental protection and stewardship, minimizing risks and preventing potential fines.	x	x
	Customer satisfaction — residential value surveys	Including these metrics in executive compensation allows for a clear assessment of individual and overall organizational performance in meeting customer needs and expectations. Residential customer satisfaction is important to us, as reliable and affordable electricity is paramount for the overall well-being of our residential customers.	x	-
	Customer satisfaction — business value surveys	Including business customer satisfaction as a metric in our compensation program encourages a culture of continuous improvement and innovation, which is important for us to support and contribute to the success and competitiveness of Florida's business community.	x	-
	Performance under FERC and NERC reliability standards(5)	We devote significant attention to consistently meeting these regulations which ensure grid reliability and well-functioning power markets.	x	-
	Equivalent forced outage rate (EFOR)(6)	EFOR is an important metric for the Company as it helps in evaluating the reliability and availability of power generation assets.	-	x
Financial	Earnings (plan-adjusted, in millions)(1)	Strong earnings are essential for NEER as they reflect financial performance, contribute to investor confidence, support dividend payments, provide resources for growth and investment and facilitate debt servicing. Strong and sustainable earnings are critical for the success and long-term growth of the Company.	-	x
	Return on equity	ROE measures our ability to generate profits from shareholders' equity, making it a good measure of how efficiently management is using equity to generate profits and grow the company. High and sustainable ROE indicates effective long-term strategic planning and execution.	-	x
	Meet budgeted cost goals (millions)	Meeting cost goals is essential as it drives profitability, enhances competitiveness, improves ROI, strengthens the customer value proposition, mitigates financial risks and drives operational efficiency. It is a critical aspect of NEER's overall business strategy and long-term success in the renewable energy sector.	-	x
	XPLR Cash Available for Distribution ("CAFD")	CAFD represents the amount of cash available for distribution to unitholders after deducting operating expenses, debt service, maintenance capital expenditures and other expenses related to the operation and maintenance of renewable energy assets. This metric provides insight into the financial performance and cash flow generation of renewable energy projects or portfolios.	-	x

	Operational Performance Metrics	Description/Rationale	FPL Metric	NEER Metric
Growth	Execute approved North American new and repowered wind projects on schedule and on budget	Executing on the construction and fulfillment of previously approved wind projects supports growth, including EPS growth.	-	x
	Execute approved North American solar and storage projects on schedule and on budget	Executing on the construction and fulfillment of previously approved solar projects supports growth, including EPS growth.	-	x
	New development or acquisition opportunities within NEER that receive approval	Growth of project backlogs gives visibility to future growth projects through focused capital investment for new, on-strategy growth opportunities.	-	x
	NextEra Energy Marketing, LLC. Growth: Pre-tax income contribution from all asset optimization, proprietary trading, origination, gas marketing and trading, full requirements net of G&A and Gexa Energy, LP	NextEra Energy Marketing is responsible for electricity and fuel management for all of NextEra Energy Resources' generation fleet, which includes the largest renewable energy portfolio in North America. As our portfolio of generation assets grows, optimizing our existing generation fleet will become a larger opportunity set, which enables us to lead the decarbonization of the U.S. economy.	-	x

After the end of 2024, the Executive Compensation Review Board ("Review Board"), whose members were Messrs. Ketchum, Bolster and Pimentel, Mrs. Kujawa and Mrs. Daggs, assessed:

(1) whether the operational performance goals had been achieved, exceeded or missed and, to the extent exceeded or missed, by what margin such goals had been exceeded or missed (as set forth in the tables above);

(2) the degree of difficulty of achieving each goal; and

(3) the Company's performance with respect to each goal as compared to the pre-established payout scale based on top-decile, top-quartile, median and sub-median performance on the same measure (industry-based, where benchmark data was available) and arrived at an aggregate determination for the Company's 2024 performance as compared to the goals.

This assessment determined the Company had achieved superior performance in 2024. The determination of the Review Board was then presented to the Compensation Committee, which had ultimate authority to accept or modify all or any part of the determination. For 2024, the Compensation Committee reviewed and discussed the Review Board's recommendations and the conclusions on which they were based and determined to accept those recommendations.

2024 ANNUAL INCENTIVE AWARDS FOR THE NEOS

Each NEO's 2024 annual incentive payout was determined based on a rating ("NextEra Energy Performance Rating") derived by combining the Company's financial performance as measured by the financial performance matrix (weighted 50%) and the Company's operational performance as compared to the operational performance goals (weighted 50%). The NextEra Energy Performance Rating for 2024 was 1.81.

FINANCIAL PERFORMANCE (50%)	OPERATIONAL PERFORMANCE (50%)	OVERALL PERFORMANCE RATING
2024 Adjusted EPS Growth: **8.2%**		
2024 Adjusted ROE: **14.7%**		
2.00	**1.62**	**1.81**

The NextEra Energy Performance Rating may be adjusted for each NEO by the Compensation Committee based on individual performance under circumstances in which the Compensation Committee determines that the formulaic calculation of the performance rating without adjustment would otherwise result in the payment of an inappropriate incentive. The Compensation Committee generally uses this aspect of the executive compensation program on a conservative basis, as it believes the formula for calculating the NextEra Energy Performance Rating ordinarily should result in appropriate incentive payments. The individual performance adjustment, when used, historically has most often ranged between ±10%.

The Compensation Committee determined the individual performance factors for 2024 based on recommendations from the CEO (for all of the NEOs other than himself). In addition to the Company's exceptional performance as described in the Executive Summary above, the Compensation Committee considered the following criteria in determining the 2024 individual performance factors:

» **Financial Goals**: Consistently achieving the Company's annual financial objectives, as well as the annual financial objectives for the executive's business unit, ensuring strong returns for our shareholders.

» **Growth Goals**: Maintaining leadership in the power market across the U.S. to meet the rapidly growing power demand, while consistently executing projects on schedule and within budget, furthering our expansion and market dominance.

» **Operational Excellence**: Keeping electric bills low, while outperforming industry standards with top-decile reliability for our customers.

» **Organizational development**: Securing top-tier talent and implementing effective succession planning strategies to uphold business continuity, drive future success and reinforce our position as an industry leader for the long term.

The following illustrates the determination of the 2024 annual incentive for each NEO:

(NEXTERA ENERGY PERFORMANCE RATING X INDIVIDUAL PERFORMANCE FACTOR) X TARGET ANNUAL INCENTIVE = ANNUAL INCENTIVE

In years where the Company's performance is above the performance of its peers on industry benchmarks, the Company expects annual incentive awards will be paid to the NEOs above target. This was the case in 2024, and the NEOs' annual incentive awards were as follows:

NAMED EXECUTIVE OFFICER	2024 ANNUAL INCENTIVE TARGET (AS A % OF BASE SALARY	2024 TARGET ANNUAL INCENTIVE ($)	NEXTERA ENERGY OVERALL PERFORMANCE RATING	2024 ANNUAL INCENTIVE AWARD ($)
John W. Ketchum	160%	2,520,000	1.81	5,014,800
Brian W. Bolster(1)	70%	665,000	1.81	1,236,900
Rebecca J. Kujawa	100%	1,100,000	1.81	2,090,000
Armando Pimentel, Jr.	100%	1,000,000	1.81	1,970,000
Charles E. Sieving	70%	892,000	1.81	1,775,100
Terrell Kirk Crews II	70%	511,200	1.81	950,800

(1) Mr. Bolster was hired on May 6, 2024. His 2024 annual incentive was not prorated as part of the overall compensation package as an inducement for him to accept the position.

2024 long-term performance-based equity compensation

EQUITY COMPENSATION MIX

In determining the appropriate mix of equity compensation components, the Compensation Committee primarily considers the following factors:

- The mix of these components at competitor and peer companies and emerging market trends
- The retention value of each element and other values important to the Company, including, for example, the tax and accounting consequences of each type of award
- The advice of the Compensation Consultant
- The perceived value to the NEO of each element

The Compensation Committee continued its practice of granting NEOs equity-based compensation, the majority of which is composed of performance share awards. This practice aligns with feedback from our shareholders, who have indicated during our shareholder outreach they favor the longer-term features of performance shares. The target award level for each equity-based element was expressed as a percentage of each NEO's target total direct compensation opportunity. The target dollar value for each component was converted to a number of shares of equivalent value (estimated present value for stock options and performance shares).

2024 MIX OF EQUITY COMPENSATION AWARDS FOR THE NEOS

In 2024, the Compensation Committee granted the following mix of equity-based compensation to the NEOs:

	MIX OF EQUITY COMPENSATION AWARDS(1)			
NAMED EXECUTIVE OFFICER	PERFORMANCE SHARES	OPTIONS	PERFORMANCE-BASED RESTRICTED STOCK	PERFORMANCE-BASED RESTRICTED XPLR COMMON UNITS
John W. Ketchum	65%	25%	3%	7%
Brian W. Bolster	60%	20%	20%	—
Rebecca J. Kujawa	60%	20%	13%	7%
Armando Pimentel, Jr.	60%	20%	20%	—
Charles E. Sieving	60%	20%	13%	7%
Terrell Kirk Crews II	60%	20%	13%	7%

(1) Calculation of percentage mix based on the target value of each grant as a percentage of each NEO's total equity-based compensation.

PERFORMANCE SHARE AWARDS GRANTED IN 2024 FOR THE PERFORMANCE PERIOD ENDING DECEMBER 31, 2026

The performance share awards granted in 2024 have a three-year performance period beginning January 1, 2024 and ending December 31, 2026; dividends are not paid or accrued during the performance period. The 2024 performance share awards have 3-year adjusted ROE and adjusted EPS growth and operational measures as performance measures, as well as a ±20% relative TSR modifier based on performance of the top ten power companies by market capitalization (as defined on page 37) at the end of a three-year period, capped at 200% of target. Consistent with prior years, the awards also have an individual performance factor ranging from ±20%, to enable the Compensation Committee to adjust payouts based on their assessment of the NEO's individual performance. The goals used for the performance share awards are different both in terms of the objectives and time-frames from the goals used under the Company's Annual Incentive Plan. The measures and their relative weights are set forth below:

PERFORMANCE MEASURE	WEIGHT	TARGET
Financial measures:		
3-year adjusted ROE and adjusted EPS growth determined using the financial matrix below:	80%	ROE: 8.4% EPS: 4.7%
Operational measures: 5% each		
3-year average employee safety — OSHA recordables/200,000 hours		1.16
Nuclear industry composite performance index (combined for FPL and NextEra Energy Resources nuclear facilities)		93.6
3-year average equivalent forced outage rate (fossil and renewable generation)		6.4%
FPL 3-year average service reliability — service unavailability (minutes)		140.1
TSR modifier		
3-year TSR relative to top ten power companies by market capitalization, which is a subset of the S&P 500 Utilities Index	±20% modifier to award payout	Midpoint of TSR at the 75th and 25th percentiles, with linear interpolation used to calculate results between the 25th and 75th percentiles

Financial matrix:

Adj. Return on Equity (ROE)				
Top Tricile	9.1%	1.00	1.50	2.00
Median	8.4%	0.75	1.00	1.50
Bottom Tricile	7.5%	0.50	0.75	1.00
		2.8%	4.7%	5.7%
		Bottom Tricile	Median	Top Tricile
		Adjusted EPS Growth		

During the performance period, performance shares are not issued. The NEO may not sell or transfer the NEOs contingent right to receive performance shares and dividends are not paid.

PAYOUT OF PERFORMANCE SHARE AWARDS GRANTED IN 2022 FOR THE PERFORMANCE PERIOD ENDED DECEMBER 31, 2024

Each NEO, other than Mr. Bolster and Mr. Pimentel, who were not employed at the time of the 2022 grant, was granted a target number of performance shares in 2022 for a three-year performance period beginning January 1, 2022 and ending on December 31, 2024. The Compensation Committee views the payout of this grant after the end of the performance period as part of each NEO's 2022 compensation, while the performance shares granted in 2024 for the performance period ending on December 31, 2026 are considered to be part of each NEO's 2024 compensation, even though the shares will not be issued, if at all, until February 2027.

In February 2025, payouts were made under the 2022-2024 performance share grants. The 2022-2024 performance grants were based on a financial performance matrix of adjusted EPS growth and adjusted ROE (weighted 80%), operational measures (weighted 20%), and TSR relative to the top ten power companies by market capitalization (+/- 20% modifier). The awards also have an individual performance factor ranging from ±20%, to enable the Compensation Committee to adjust payouts based on their assessment of the NEO's individual performance.

For the performance period from January 1, 2022 through the end of 2024, NextEra Energy's relative TSR was -13.02% and ranked eighth among the top ten power companies by market capitalization, resulting in a relative TSR modifier of -20%. Consistent with prior years, for the purpose of calculating payout percentages, the TSRs at the 75th and 25th percentiles are defined as the TSRs of the peers that rank nearest, rounding up, to the given percentiles. The TSR calculation requires a 20-trading day average to determine the beginning average and ending average price for the common stock of NextEra Energy and each member of the peer group.

	RELATIVE TSR PERCENTILE RANKING FOR THREE YEAR PERFORMANCE PERIOD	TSR RESULTS FOR THREE YEAR PERFORMANCE PERIOD	MODIFIER RESULT
NextEra Energy		**-13.02%**	**0.80**
Top Ten Power Companies by Market Capitalization (a subset of the S&P 500 Utilities Index)	≥75th Percentile	47.84%	120%
	Midpoint	17.41%	100%
	≤25th Percentile	-13.02%	80%

Based on our performance during the performance period, the 2022 performance share award received an overall rating of 1.58, determined as shown below.

PERFORMANCE MEASURE(1)	WEIGHT	RESULT	PAYOUT AS A % OF TARGET
Adjusted EPS growth and adjusted ROE	80%	2.00	200%
Operational measures	20%	1.90	190%
Overall rating		**1.98**	**198%**
Relative TSR modifier	±20%	0.80	80%
Overall rating (after applying relative TSR modifier and individual performance factors)(1)		1.58	158%

(1) Each NEO's individual performance factor ranges from ±20% and can only modify the overall rating prior to applying the TSR modifier. Despite the excellent performance of the NEOs, the Committee elected not to utilize the individual performance factor, and the NEOs received an overall rating of 1.58.

Applying the overall rating results to the target performance shares resulted in the following performance share award payouts for each of the NEOs:

NAMED EXECUTIVE OFFICER	TARGET PERFORMANCE SHARES FOR PERFORMANCE PERIOD 1/1/22-12/31/24	PAYOUT FACTOR	PERFORMANCE SHARES EARNED
John W. Ketchum	81,354	1.58	128,539
Brian W. Bolster(1)	—	—	—
Rebecca J. Kujawa	47,203	1.58	74,580
Armando Pimentel, Jr.(1)	—	—	—
Charles E. Sieving	20,447	1.58	32,306
Terrell Kirk Crews II	11,333	1.58	17,906

(1) Messrs. Bolster and Pimentel did not receive a 2022 performance share award as they were not employed by the Company at that time.

PERFORMANCE-BASED RESTRICTED STOCK GRANTED IN 2024

The performance objective for performance-based restricted stock is adjusted earnings of $3.0 billion. The shares of performance-based restricted stock granted in 2024 will not vest unless and until the Compensation Committee certifies that NextEra Energy's adjusted earnings for each of 2024, 2025 and 2026, respectively, equal or exceed $3.0 billion; vesting occurs one-third per year for three years for each year the corporate performance objective is met. If the adjusted earnings objective is not met in any year, performance-based restricted stock scheduled to vest in that year is forfeited.

Because the Compensation Committee intends for the grant date present value of performance-based restricted stock awards to equal the fair market value of an equivalent number of shares of the Company's common stock absent the performance and vesting conditions, dividends are paid on performance-based restricted stock awards as dividends are paid on the common stock. However, any dividends paid on performance-based restricted stock awards that do not vest must be repaid within 30 days following forfeiture of the award. In addition, NEOs have the right to vote their shares of performance-based restricted stock.

PERFORMANCE-BASED RESTRICTED XPLR COMMON UNITS GRANTED IN 2024

In February 2024, NEOs who are also officers of XPLR were granted XPLR performance-based restricted common units ("XPLR Awards"). The Compensation Committee believes the proposed XPLR Awards further align the incentive compensation of these NEOs to activities that promote the growth of long-term value for our shareholders. After considering this and other factors, the Board of Directors of XPLR (the "XPLR Board") in February 2024 approved grants of XPLR Awards to those Company NEOs who also are officers of XPLR, as well as to other officers and employees of the Company or its affiliates who are responsible for significant XPLR activities.

The XPLR Awards received by the NEOs did not increase the NEOs' overall incentive compensation opportunity, but instead replaced on a dollar-for-dollar basis approximately 7% of the aggregate grant date value of the portion of their long-term performance-based awards in 2024 that otherwise would have been issued in the form of performance-based restricted stock of the Company. The performance objective for the XPLR Awards is adjusted EBITDA of $900 million. Adjusted EBITDA is XPLR's consolidated net income, as reported in its audited financial statements as determined in accordance with GAAP, plus interest expense, income tax expense, depreciation and amortization less certain non-cash, non-recurring items. Therefore, the XPLR Awards granted in 2024 will not vest unless and until the XPLR Board certifies that XPLR's adjusted EBITDA for 2024, 2025 and 2026, respectively, equals or exceeds $900 million; the awards vest one-third per year for three years for each year the XPLR performance objective is met. If the objective of adjusted EBITDA of $900 million is not met in any year, performance-based restricted XPLR common units scheduled to vest in that year are forfeited.

Distributions are paid on performance-based restricted XPLR common units as and when declared by XPLR but are subject to repayment by the NEO if awards are forfeited prior to vesting. In addition, NEOs have the right to vote their performance-based restricted XPLR common units.

The XPLR Awards were made pursuant to the NextEra Energy Partners, LP 2014 Long Term Incentive Plan ("NEP 2014 LTIP"). XPLR will be reimbursed by the Company for the grant date fair value of all XPLR Awards granted to employees and officers of the Company or its affiliates.

NON-QUALIFIED STOCK OPTION AWARDS IN 2024

The Compensation Committee grants non-qualified stock options that vest and become exercisable one-third per year for three years, beginning approximately one year from date of grant. Stock options have an exercise price equal to the closing price of NextEra Energy common stock on the grant date (February 15, 2024) and generally expire ten years from date of grant. The NextEra Energy, Inc. 2021 Long Term Incentive Plan (the "2021 LTIP") prohibits repricing of awarded options without shareholder approval.

EQUITY GRANT PRACTICES

Stock option awards are granted by the Compensation Committee to the NEOs each year in mid-February, which is a date that is normally set two years in advance. The Compensation Committee believes granting stock options in this way is appropriate because the Company typically releases year-end earnings in late January, so all relevant information should be available to the market on the grant date. Stock option awards may also be made to new executive officers upon hire or promotion, generally coincident with the date of hire or promotion or the Compensation Committee meeting next following the date of hire or promotion. The Compensation Committee does not seek to time stock option grants to take advantage of material non-public information ("MNPI"), either positive or negative, about the Company which has not been publicly disseminated. The Company has not timed the disclosure of MNPI for the purpose of affecting the value of executive compensation. The exercise price of options granted is equal to the closing market price of NextEra Energy's common stock on the effective date of the grant.

The following table provides information regarding stock options granted to our NEOs in 2024 within four business days before the filing of a periodic report or current report disclosing MNPI or within one business day after the filing of such information.

NAME	GRANT DATE	NUMBER OF SECURITIES UNDERLYING THE AWARD	EXERCISE PRICE OF THE AWARD ($/SHARE)	GRANT DATE FAIR VALUE OF THE AWARD	PERCENTAGE CHANGE IN THE CLOSING MARKET PRICE OF THE SECURITIES UNDERLYING THE AWARD BETWEEN THE TRADING DAY ENDING IMMEDIATELY PRIOR TO THE DISCLOSURE OF MNPI AND THE TRADING DAY BEGINNING IMMEDIATELY FOLLOWING THE DISCLOSURE OF MNPI
John W. Ketchum	2/15/2024	230,700	57.27	2,599,989	-1.2%
Brian W. Bolster	5/6/2024	43,899	71.25	679,996	2.6%
Rebecca J. Kujawa	2/15/2024	120,674	57.27	1,359,996	-1.2%
Armando Pimentel, Jr.	2/15/2024	106,477	57.27	1,199,996	-1.2%
Charles E. Sieving	2/15/2024	45,244	57.27	509,900	-1.2%
Terrell Kirk Crews II	2/15/2024	34,755	57.27	391,689	-1.2%

Other practices and policies related to compensation

Stock ownership and retention policies

The Company believes it is important for executive officers to accumulate a significant amount of NextEra Energy common stock to align officers' interests with those of the Company's shareholders.

NextEra Energy's NEOs (and all other officers) are subject to a stock ownership policy and a stock retention policy. The Company believes these policies strongly reinforce NextEra Energy's executive compensation philosophy and objectives. At the same time, the Company recognizes the accumulation of a large, undiversified position in NextEra Energy common stock can at some point create undesired incentives, and it permits its officers some degree of diversification once the target level of holdings is reached.

Under the stock ownership policy, officers are expected, within five years after appointment to office, to own NextEra Energy common stock with a value equal to a multiple of their base salaries. Shares of NextEra Energy common stock and share units held in NextEra Energy's employee benefit plans and deferred compensation plan are credited toward meeting this requirement. Unvested shares of performance-based restricted stock, shares subject to unpaid performance share awards and unexercised options do not count toward the calculation of required holdings. The current multiples are as follows:

POSITION	STOCK OWNERSHIP REQUIREMENT, AS A MULTIPLE OF BASE SALARY RATE	COMPLIANCE PERIOD	COMPLIANCE STATUS
CEO	7x	Within five years after appointment to office	As of December 31, 2024, all NEOs, other than Mr. Bolster, who joined the Company in 2024, owned common stock in excess of their requirements
Senior executive officers	3x		
Other officers	1x		

Under the stock retention policy, until such time as the requirements of the stock ownership policy are met, NextEra Energy expects executive officers to retain (and not sell) a number of shares equal to at least two-thirds of shares acquired through equity compensation awards (cumulatively, from the date of appointment as an executive officer). In addition, senior executive officers must retain all shares of performance-based restricted stock for a minimum of 24 months after vesting (net of shares withheld for, or used to pay, taxes).

Officers who fail to comply with the retention policy may not be eligible for future equity-based compensation awards for a two-year period. The CEO may approve the modification or reduction of the minimum retention requirements (other than for himself) to address the special needs of a particular officer, although to date there have been no such modifications or reductions.

Clawback provisions

The Company has an incentive compensation recoupment, or "clawback," policy which provides for recoupment of Incentive Compensation from current and former executive officers in the event of a Triggering Event (the "Clawback Policy"). Capitalized terms used but not defined herein shall have the same respective meanings given to them in the Clawback Policy.

"Incentive Compensation" means any compensation, including but not limited to annual cash incentives under the Executive Annual Incentive Plan (or any successors thereto), and long-term equity incentives under the Amended and Restated 2011 Long Term Incentive Plan and the 2021 Long Term Incentive Plan, that was granted, earned or vested based in whole or in part upon the attainment of one or more Financial Reporting Measures; provided however, for the avoidance of doubt, "Incentive Compensation" does not include any long-term incentives under the XPLR Infrastructure, LP 2024 Long Term Incentive Plan or under any other incentive plan of XPLR Infrastructure, LP in effect from time to time.

"Triggering Event" means a decision by the Audit Committee of the Board that an accounting restatement of the Company's previously published financial statements is required due to material non-compliance by the Company with any financial reporting requirement under the federal securities laws, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period or, if earlier, the date such a decision should have been made.

If a Triggering Event occurs, the Company shall (to the extent permitted by applicable law) promptly recoup any Incentive Compensation received during the Recoupment Period by any individual who served as an Executive Officer at any time during the performance period applicable to such Incentive Compensation that was in excess of that which such Executive Officer would have received after giving effect, as applicable, to the accounting restatement associated with the Triggering Event. The incentive compensation to be recouped will be in an amount and form determined in the judgment of the Board following recommendation by the Compensation Committee (which recommendation shall not be binding), in accordance with the applicable listing standards or policies of the national stock exchange upon which the Company's shares are listed.

The Company shall not be permitted to insure or indemnify any Executive Officer against (i) the loss of any Incentive Compensation that is recouped in accordance with the Clawback Policy, or (ii) any claims relating to the Company's enforcement of its rights under the Clawback Policy.

Anti-hedging policy

The Company's Trading Policy, which applies to all directors, officers and employees of the Company (collectively, referred to as "insiders" in the Trading Policy), prohibits hedging transactions with respect to securities of the Company. The Company considers it improper and inappropriate for any Company insider to engage in short-term or speculative transactions in the Company's securities. Transactions in options, puts, calls or other derivative securities are prohibited. Additionally, certain forms of hedging transactions with respect to the Company's securities, such as prepaid variable forwards, equity swaps and collars, are prohibited. These transactions allow an insider to continue to own covered securities without the full risks and rewards of ownership and the insider may no longer have the same objectives as the Company's other shareholders. Therefore, these transactions are prohibited under the Trading Policy.

Anti-pledging policy

The Company's Trading Policy prohibits pledging transactions with respect to securities of the Company. Because a margin sale or foreclosure sale may occur at a time when the pledgor is aware of MNPI or otherwise is not permitted to trade in Company securities, insiders are prohibited from holding Company securities in a margin account or pledging Company securities as collateral for a loan.

Risk oversight

The Compensation Committee oversees compensation-related risks, including annually reviewing management's assessment of risks related to employee compensation programs. In February 2024 and 2025, the Compensation Committee reviewed management's analysis of the Company's compensation program risks and mitigation of those risks, as well as the Company's ongoing compensation risk management process. The Compensation Committee reviewed, among other matters, the Board's overall role in the oversight of the Company's risks, the Compensation Committee's role in the oversight of compensation-related risks, the relationship of certain risks to the Company's compensation programs and policies and the compensation risk-related risk mitigation practices and controls which the Company has in place.

Additional 2024 compensation elements

BENEFITS

NextEra Energy provides its executive officers with a comprehensive benefits program which includes health and welfare, life insurance and other personal benefits. For programs to which employees contribute premiums, executive officers pay the same premiums as other similarly situated exempt employees. Retirement and other post-employment benefits are discussed under Post-Employment Compensation. These benefits are an integral part of the total compensation package for NEOs, and the aggregate value is included in the information reviewed by the Compensation Committee annually to ensure the reasonableness and appropriateness of total rewards. In addition, NextEra Energy believes the intrinsic value placed on personal benefits by the NEOs is generally greater than the incremental cost of those benefits to the Company.

PERSONAL BENEFITS

NextEra Energy provides its executive officers with personal benefits which, in many cases, improve efficiency by allowing the executive officers to focus on their critical job responsibilities and/or increasing the hours they can devote to work. Some of these benefits also serve to better secure the safety of the executive officers and their families. The Compensation Committee and its Compensation Consultant periodically review the personal benefits offered by the Company to ensure the program is competitive and producing the desired results. The Compensation Committee believes the benefits the Company derives from these personal benefits more than offset their incremental cost to the Company.

See footnote 2 to *Table 1b: 2024 Supplemental All Other Compensation* for a description of the personal benefits provided to the NEOs for 2024.

USE OF COMPANY-OWNED AIRCRAFT

Company aircraft are available to the NEOs, as well as other employees and directors, for business travel, which includes, in the judgment of the Governance & Nominating Committee, travel by NEOs to Company-approved outside board meetings and travel in connection with physical examinations. Among other advantages, business use of the aircraft by executives maximizes time efficiencies, provides a confidential environment for business discussions and enhances security.

NextEra Energy permits limited non-business use of Company aircraft by NEOs when that use does not interfere with the use of Company aircraft for business purposes. Non-business use is generally discouraged, however, and must be approved in advance by the CEO. NEOs must pay the Company for their non-business use based on the rate prescribed by the IRS for valuing non-commercial flights. An NEO traveling on Company aircraft for business purposes may, with the approval of the CEO, be accompanied by the NEO's guests, spouse and/or other family members. In this circumstance, there is essentially no incremental cost to the Company associated with transporting the additional passengers. Unless the travel is important to carrying out the business responsibilities of the NEO, however, the Company generally requires payment by the NEO for these passengers based on the rates described above. All non-business use of Company aircraft is reported to and reviewed by the Governance & Nominating Committee annually. In 2024, the NEOs' use of Company aircraft for non-business purposes represented approximately 98 passenger flight hours and travel to Company-approved outside board meetings and annual physical examinations represented an additional approximately 25 passenger flight hours. Company aircraft were used for a total of approximately 3,491 passenger flight hours in the aggregate in 2024.

POLICY ON TAX REIMBURSEMENTS ON EXECUTIVE PERQUISITES

In accordance with the NextEra Energy, Inc. Policy on Tax Reimbursements on Executive Perquisites, the Company does not provide tax reimbursements on perquisites to the NEOs. In circumstances where the Compensation Committee deems such an action appropriate, the Company may provide tax reimbursements to executives as part of a plan, policy or arrangement applicable to a broad base of management employees of the Company, such as a relocation or expatriate tax equalization policy.

Post-employment compensation

NextEra Energy expects continued and consistent high levels of individual performance from all executive officers as a condition of continued employment. The Company has in the past terminated the employment of executive officers who were unable to sustain the expected levels of performance, and it is prepared to do so in the future should that become necessary. All of the NEOs, including the CEO, are "employees at will."

Set forth below is a description of the agreements and programs that may provide for compensation should an NEO's employment with the Company terminate under specified circumstances.

Severance Plan

The NextEra Energy, Inc. Executive Severance Benefit Plan (the "Severance Plan") provides for the payment of severance benefits to the NEOs and to certain other senior executives if their employment with the Company is involuntarily terminated in specified circumstances. The purpose of the Severance Plan is to retain the covered senior executives and encourage dedication to their duties by ensuring the equitable treatment of those who may experience an involuntary termination, as defined in the Severance Plan. The Severance Plan provides severance benefits following involuntary termination in exchange for entry by the executive into a release of claims against the Company and an agreement to adhere to certain non-competition and related covenants protective of the Company and its affiliates. Following a covered involuntary termination and the execution of the release and other agreement, the executive would receive a cash payment equal to two times the executive's annual base salary plus two times the executive's target annual incentive compensation for the year of termination, payable in two equal annual installments. In addition, the executive's outstanding equity and equity-based awards would vest pro rata, and become payable at the end of any applicable performance periods, subject to the attainment by the Company of the specified performance objectives. The executive also would receive certain ancillary benefits, including outplacement assistance or payment in an amount equal to the value of the outplacement assistance. Amounts payable under the Severance Plan are subject to a cap specified in the Severance Plan.

The Company may amend or terminate the Severance Plan, in full or in part, at any time, but if an amendment or termination would affect the rights of an executive, the executive must agree in writing to the amendment or termination. The Severance Plan does not provide for the payment of severance benefits upon terminations governed by the terms of the executive retention employment agreement ("Retention Agreement") described below.

Change in control

Each of the NEOs is a party to a Retention Agreement with the Company. The Compensation Committee has concluded the Retention Agreements are desirable in order to align NEO and shareholder interests under some unusual conditions, as well as useful and, in some cases, necessary to attract and retain senior executive talent.

In connection with a change in control of the Company, it can be important to secure the dedicated attention of executive officers whose personal positions are at risk and who have other opportunities readily available to them. By establishing compensation and benefits payable under various merger and acquisition scenarios, change in control agreements enable the NEOs to set aside personal financial and career objectives and focus on maximizing shareholder value. These agreements also help the officer to maintain an objective and neutral perspective in analyzing opportunities that may arise. Furthermore, they ensure continuity of the leadership team at a time when business continuity is of paramount concern. Without the Retention Agreements, the Company would have a greater risk of losing key executives in times of uncertainty.

Retention Agreements entered into since 2009 do not include excise tax gross-ups. Retention Agreements entered into since 2021 require double-trigger equity vesting upon a change of control; i.e., there must be both a change of control and qualifying termination for accelerated vesting to occur. The material terms of the Retention Agreements are described under Potential Payments Upon Termination or Change in Control beginning on page 75.

Retirement programs

EMPLOYEE PENSION PLAN AND 401(K) PLAN

NextEra Energy maintains two retirement plans which qualify for favorable tax treatment under the Internal Revenue Code ("Code"): a non-contributory defined benefit pension plan and a defined contribution 401(k) plan. These plans are available to substantially all NextEra Energy employees. Each of the NEOs participates in both plans. The pension plan is more fully described following *Table 5: Pension Benefits.*

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP")

Current tax laws place various limits on the benefits payable under tax-qualified retirement plans, such as NextEra Energy's defined benefit pension plan and 401(k) plan, including a limit on the amount of annual compensation that can be taken into account when applying the plans' benefit formulas. Therefore, the retirement incomes provided to the NEOs by the qualified plans generally constitute a smaller percentage of final pay than is typically the case for other Company employees. In order to make up for this and maintain the market-competitiveness of NextEra Energy's executive retirement benefits, NextEra Energy maintains an unfunded, non-qualified SERP for its executive officers, including the NEOs. For the NEOs, compensation included under the SERP is annual base salary plus the actual annual cash incentive award, as opposed to the compensation included under the qualified plans, which is annual base salary only. NextEra Energy believes it is appropriate to include annual cash incentive awards for purposes of determining retirement plan benefits (both defined benefit pension and 401(k)) for the NEOs in order to ensure the NEOs can replace in retirement a proportion of total compensation similar to that replaced by other employees participating in the Company's defined benefit pension and 401(k) plans, bearing in mind that base salary alone constitutes a relatively smaller percentage of an NEO's total compensation.

For additional information about the defined benefit plan benefit formulas under the SERP, see *Table 5: Pension Benefits* and accompanying descriptions.

DEFERRED COMPENSATION PLAN

NextEra Energy sponsors a non-qualified, unfunded Deferred Compensation Plan, which allows eligible highly compensated employees, including the NEOs, voluntarily and at their own risk, to elect to defer certain forms of compensation prior to the compensation being earned and vested. NextEra Energy makes this opportunity available to its highly compensated employees as a financial planning tool and an additional method to save for retirement. Deferrals by executive officers generally result in the Company deferring its obligation to make cash payments or issue shares of its common stock to those executive officers.

The Compensation Committee does not view the Deferred Compensation Plan as providing executives with additional compensation. Participants in the Deferred Compensation Plan are general creditors of the Company and the deferral of the payment obligation provides a financial advantage to the Company. For additional information about the Deferred Compensation Plan, see *Table 6: Non-qualified Deferred Compensation* and accompanying descriptions.

Tax considerations

The Compensation Committee carefully considers the tax impact of the Company's compensation programs on NextEra Energy as well as on the NEOs. However, the Compensation Committee believes decisions regarding executive compensation should be primarily based on whether they result in positive long-term value for the Company's shareholders and other important stakeholders. While the Compensation Committee believes shareholder interests are best served if it retains discretion and flexibility in awarding compensation, even though some compensation awards may result in non-deductible compensation expenses, the Compensation Committee intends to maintain strong pay-for-performance alignment of executive compensation arrangements notwithstanding loss of deductibility due to repeal of the exemption for performance-based compensation.

COMPENSATION COMMITTEE REPORT

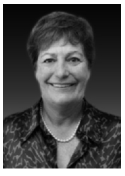
The Compensation Committee has reviewed and discussed with management the Compensation Discussion & Analysis required by applicable SEC rules which precedes this Report and, based on its review and that discussion, the Compensation Committee recommended to the Board that the Compensation Discussion & Analysis set forth above be included in the Company's proxy statement for the 2025 annual meeting of shareholders and incorporated by reference into the Company's Annual Report on Form 10-K for the year ended December 31, 2024.

Respectfully submitted,

THE COMPENSATION COMMITTEE

Kirk S. Hachigian, *Chair*

James L. Camaren



Amy B. Lane

Dev Stahlkopf

Darryl L. Wilson

COMPENSATION TABLES

When reviewing the narrative, tables and footnotes which follow, note that, in order to meet the goals and objectives of NextEra Energy's executive compensation program as described in the Compensation Discussion & Analysis, the Compensation Committee primarily focuses on, and values, each NEO's total compensation opportunity at the beginning of the relevant performance periods. Since many elements of total compensation are variable, based on performance and are not paid to the NEO for one, two or three years (and in some instances longer) after the compensation opportunity is first determined, the amounts reported in some of the tables in this proxy statement may reflect compensation decisions made prior to 2024 and in some cases reflect amounts different from the amounts that may ultimately be paid.

Table 1a: 2024 summary compensation table

The following table provides certain information about the compensation paid to, or accrued on behalf of, the NEOs in 2024. It is important to keep in mind the following when reviewing the table:

- The amounts shown in the "Stock Awards" and the "Option Awards" columns are based on the aggregate grant date fair value of awards computed under applicable accounting rules for all equity compensation awards.
- The "Change in Pension Value and Non-qualified Deferred Compensation Earnings" column reflects the change in the present value of the pension benefit payable to each NEO in the applicable year. These changes in present value are not related to any compensation decision on the part of the Compensation Committee.

TABLE 1A: 2024 SUMMARY COMPENSATION TABLE

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
NAME AND PRINCIPAL POSITION (1)	YEAR	SALARY (3) ($)	BONUS(4) ($)	STOCK AWARDS (5)(6)(7) ($)	OPTION AWARDS (5) ($)	NON-EQUITY INCENTIVE PLAN COMPENSATION (8) ($)	CHANGE IN PENSION VALUE AND NON-QUALIFIED DEFERRED COMPENSATION EARNINGS (9)(10) ($)	ALL OTHER COMPENSATION (9)(11) ($)	TOTAL ($)
John W. Ketchum(2), *Chairman, President and CEO of NextEra Energy and Chairman of FPL*	2024	1,575,000	0	11,053,947	2,599,989	5,014,800	918,853	441,009	21,603,598
	2023	1,575,000	0	10,568,909	2,599,993	4,636,800	811,026	399,396	20,591,124
	2022	1,483,333	0	8,436,431	2,187,500	4,500,000	475,209	331,856	17,414,329
Brian W. Bolster, *Executive Vice President, Finance and Chief Financial Officer of NextEra Energy and FPL*	2024	628,462	1,500,000	5,324,182	679,996	1,236,900	0	244,870	9,614,410
Rebecca J. Kujawa, *President and Chief Executive Officer of NextEra Energy Resources*	2024	1,100,000	0	7,403,858	1,359,996	2,090,000	453,542	195,464	12,602,860
	2023	1,100,000	0	7,111,077	1,359,993	2,024,000	407,530	173,876	12,176,476
	2022	979,167	0	5,487,265	1,099,995	2,000,000	288,824	146,585	10,001,836
Armando Pimentel, Jr., *President and Chief Executive Officer of FPL*	2024	1,000,000	0	6,532,879	1,199,996	1,970,000	359,127	289,155	11,351,157
	2023	896,154	0	6,274,511	1,199,997	1,840,000	117,429	235,316	10,563,407
Charles E. Sieving, *Executive Vice President, Chief Legal, Environmental and Federal Regulatory Affairs Officer of NextEra Energy and Executive Vice President of FPL*	2024	1,274,300	0	2,775,559	509,900	1,775,100	525,247	225,166	7,085,272
	2023	1,274,300	0	2,665,736	509,894	1,641,300	423,332	207,615	6,772,178
	2022	1,190,900	0	2,376,928	476,495	1,429,080	380,269	174,889	6,028,560
Terrell Kirk Crews II, *Executive Vice President Chief Risk Officer of NextEra Energy*	2024	730,300	0	2,132,490	391,689	950,800	227,823	112,415	4,545,517
	2023	730,300	0	2,048,115	391,691	940,600	204,299	103,552	4,418,556
	2022	630,400	0	1,317,395	264,094	889,000	103,644	91,662	3,296,195

(1) Mr. Ketchum was appointed Chairman of FPL on February 15, 2023. Mr. Bolster joined the Company on May 6, 2024 as executive vice president, finance and chief financial officer of NextEra Energy and FPL. Mr. Crews served as executive vice president, finance and chief financial officer of NextEra Energy and FPL until his appointment as executive vice president and chief risk officer of NextEra Energy effective May 6, 2024. Mr. Pimentel rejoined the Company on January 25, 2023 and was appointed CEO of FPL on February 15, 2023.

(2) In accordance with SEC rules, for 2024, NextEra Energy's last completed fiscal year, the ratio of the annual total compensation of Mr. Ketchum, the principal executive officer ("PEO"), to NextEra Energy's median employee's annual compensation was 147 to 1. The median employee's annual total compensation was $146,532. The total annual compensation of the PEO for purposes of calculating the pay ratio was $21,603,598. We identified a new median employee for 2024 from our employee population as of December 31, 2024. On that date, NextEra Energy had 16,774 U.S.-based active employees. NextEra Energy had 91 employees in Canada that were excluded in accordance with SEC rules from the median employee determination as they represented less than 5% of the Company's workforce. The compensation measure used to identify the median employee was total cash compensation, and no employee's compensation was annualized. Total cash compensation is the predominant form of employee remuneration. All of the elements of the employee's 2024 compensation were combined in accordance with the applicable SEC rules.

(3) Amounts in the salary column are composed of executive salaries earned for the year shown. Mr. Bolster joined the Company on May 6, 2024 with an annual salary of $950,000; the amount shown reflects the prorated amount earned in 2024.

(4) The amount in the bonus column represents the signing bonus paid to Mr. Bolster upon his commencement of employment; subject to three-year repayment terms.

(5) The amounts shown represent the aggregate grant date fair value of equity-based compensation awards granted during the relevant year, valued in accordance with applicable accounting rules, without reduction for estimated forfeitures. See Note 11 Equity — Stock-Based Compensation to the consolidated financial statements in the Company's Annual Report on Form 10-K for the years ended December 31, 2024, December 31, 2023 and December 31, 2022 for the assumptions used in this valuation.

(6) Includes performance-based restricted stock and performance share awards valued based on the probable outcome of the performance conditions as of the grant date, and for Mrs. Kujawa and Messrs. Ketchum, Crews, and Sieving, performance-based restricted XPLR common units. The grant date fair value of performance-based restricted XPLR common units is measured based upon the closing market price of XPLR common units as of the date of grant, February 20, 2024. With respect to the performance shares granted in 2024, 2023 and 2022 to all NEOs, a performance rating assumption of 1.40 (i.e., target shares multiplied by 1.40) was used (in accordance with applicable accounting guidance) to value such performance share awards and grant date fair value for all NEOs was determined on the grant date using the Monte-Carlo simulation process with the following variables:

DESCRIPTION	MARKET	VOLATILITY	YIELD	INTEREST RATE	EXPECTED LIFE	FAIR VALUE
For the 2/15/2024 grant	$57.27	27.00%	3.01%	4.34%	2.87 yr.	$53.89
For the 2/16/2023 grant	$75.69	27.17%	2.45%	4.34%	2.87 yr.	$70.42
For the 2/17/2022 grant	$75.38	29.85%	2.42%	1.67%	2.87 yr.	$66.39

(7) The maximum payout of performance shares granted in 2024 is 2.00 times target. Therefore, the maximum aggregate grant date fair value of the awards granted in 2024 is: for Mr. Ketchum, 265,462 shares, or $14,305,747; for Mr. Bolster, 62,404 shares granted May 6, 2024 at a fair value of $71.98 per share, or $4,491,840; for Mrs. Kujawa, 160,218 shares, or $8,634,148; for Mr. Pimentel, 141,370 shares, or $7,618,429; for Mr. Sieving, 60,062 shares, or $3,236,741 and for Mr. Crews, 46,148 shares, or $2,486,916.

(8) Includes the amount earned by each NEO, as applicable, payable in February of the following year, with respect to 2024, 2023 and 2022 under the Annual Incentive Plan.

(9) NextEra Energy maintains both defined benefit and defined contribution retirement plans (as described in Compensation Discussion & Analysis — Post-Employment Compensation — Retirement Programs). Company contributions to defined benefit and defined contribution retirement plans (both qualified and non-qualified) are allocated between columns (H) and (I), respectively.

(10) All amounts in this column reflect the one-year change in the present value of each NEO's accumulated benefit under the tax-qualified defined benefit employee pension plan and the SERP. The Deferred Compensation Plan does not permit above-market interest to be credited and, therefore, no above-market interest was credited in 2024, 2023 and 2022.

(11) Additional information about the amounts for 2024 set forth in the "All Other Compensation" column may be found in *Table 1b: 2024 Supplemental All Other Compensation,* which immediately follows.

Table 1b: 2024 supplemental "all other compensation" table

The following table (Table 1b) provides additional information for 2024 regarding column (J) of Table 1a: 2024 Summary Compensation Table.

TABLE 1B: 2024 SUPPLEMENTAL ALL OTHER COMPENSATION

NAME	TOTAL FROM SUMMARY COMPENSATION TABLE ($)	CONTRIBUTIONS TO DEFINED CONTRIBUTION PLANS[1] ($)	PERQUISITES AND OTHER PERSONAL BENEFITS[2] ($)
John W. Ketchum	441,009	295,061	145,948
Brian W. Bolster	244,870	27,439	217,431

NAME	TOTAL FROM SUMMARY COMPENSATION TABLE ($)	CONTRIBUTIONS TO DEFINED CONTRIBUTION PLANS(1) ($)	PERQUISITES AND OTHER PERSONAL BENEFITS(2) ($)
Rebecca J. Kujawa	195,464	148,391	47,074
Armando Pimentel, Jr.	289,155	134,901	154,255
Charles E. Sieving	225,166	138,492	86,674
Terrell Kirk Crews II	112,415	79,369	33,047

(1) NextEra Energy maintains both defined benefit and defined contribution retirement plans. Amounts attributable to the defined benefit plans are reported in *Table 1a: 2024 Summary Compensation Table* under column (H), "Change in Pension Value and Non-qualified Deferred Compensation Earnings."

Amounts attributable to the defined contribution plans are reported under column (I), "All Other Compensation," and are further described below under Additional Disclosure Related to Pension Benefits Table. This column includes employer matching contributions to the Company's qualified 401(k) plan of $16,388 for Mrs. Kujawa and Messrs. Ketchum, Pimentel, Sieving and Crews and $9,755 for Mr. Bolster, plus the Company's contributions to the non-qualified defined contribution portion of the SERP.

(2) This column includes the aggregate incremental cost to NextEra Energy of providing personal benefits to the NEOs. For each NEO, the personal benefits reported for 2024 in this column include:

» annual premiums for $5 million in umbrella coverage under a group personal excess liability insurance policy;

» reimbursement for professional financial planning and legal services (a grandfathered perquisite), for Messrs. Ketchum and Sieving;

» for Messrs. Ketchum and Sieving, the cost of the officer's participation in an executive vehicle program, which includes use of a Company-leased passenger vehicle, fuel and other ancillary costs (the incremental cost incurred for which was $31,649 for Mr. Ketchum, and $37,708 for Mr. Sieving, which are grandfathered perquisites);

» for Mr. Sieving, costs of executive physical examinations;

» for Mr. Bolster, relocation expenses of $180,000;

» for Messrs. Ketchum of $5,000, Sieving of $20,000 and Crews of $5,973, and Mrs. Kujawa of $20,000, in matching gifts to educational institutions;

» for Messrs. Crews and Pimentel and Mrs. Kujawa, a cash perquisite allowance of $25,000 and a pro-rated cash perquisite allowance of $15,385 for Mr. Bolster all in lieu of executive vehicle program; and

» for Messrs. Ketchum, Pimentel and Sieving, costs for maintenance of a residential home security system and central station monitoring.

Executive perquisites are a part of a holistic compensation strategy, designed to attract, retain and motivate exceptional leadership. Our perquisites serve several purposes including:

1) Improving retention by providing benefits designed to maintain our competitiveness for top talent.
2) Ensuring the safety and security of our executives through perquisites such as home security systems or personal use of a corporate aircraft, which is in the best interest of the Company.
3) Supporting overall health and well-being by covering the cost of executive physical examinations.

The Compensation Committee regularly reviews the executive perquisite program to ensure its continued alignment with our strategic goals and shareholders' interests.

For Messrs. Ketchum and Sieving, the personal benefits reported in this column also include premiums for a grandfathered life insurance benefit in an amount equal to 2.5 times salary. For all NEO's, the personal benefits reported in this column also include the incremental cost to the Company for personal use of Company-owned aircraft, which is the variable operating costs of such use, net of payments to the Company by or on behalf of the NEOs. Variable operating costs include fuel, trip-related maintenance, crew travel expenses, on-board catering, landing fees, trip-related hangar/parking costs, excise taxes and other miscellaneous variable costs. The total annual variable costs are divided by the annual number of statute miles the Company aircraft flew to derive an average variable cost per mile. The incremental cost incurred was $87,780 for Mr. Ketchum, $19,436 for Mr. Bolster, $124,302 for Mr. Pimentel and $3,487 for Mr. Sieving, and no such cost was incurred for Mrs. Kujawa or Mr. Crews.

Table 2: 2024 grants of plan-based awards

The following table provides information about the cash and equity incentive compensation awarded to the NEOs in 2024. It is important to keep in mind the following when reviewing the table:

» Columns (C), (D) and (E) below set forth the range of possible payouts established under the Annual Incentive Plan for 2024 and are not amounts actually paid to the NEOs. The actual amounts paid with respect to 2024 under the Annual Incentive Plan, which is a Non-Equity Incentive Plan, as that term is used in the heading for columns (C), (D) and (E) of this table, are set forth in *Table 1a: 2024 Summary Compensation Table* in column (G), entitled "Non-Equity Incentive Plan Compensation."

- The number of shares listed under “Estimated Future Payouts Under Equity Incentive Plan Awards” (columns (G) and (H)) represent 2024 grants of performance shares, performance-based restricted stock and performance-based restricted XPLR common units, the material terms of which are described below this table.
- The number of shares listed under “All Other Option Awards: Number of Securities Underlying Options” (column (J)) and the exercise price set forth under “Exercise or Base Price of Option Awards” (column (K)) represent the number and exercise price of 2024 grants of non-qualified stock options, the material terms of which are described below this table.
- In the column headed “Grant Date Fair Value of Stock and Option Awards” (column (L)), the top number is the grant date fair value of the performance share award, the next number is the grant date fair value of the performance-based restricted stock award, the third number is the grant date fair value of the stock options granted and the fourth number is the grant date fair value of XPLR performance-based restricted common units, as applicable.

TABLE 2: 2024 GRANTS OF PLAN-BASED AWARDS

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
		ESTIMATED FUTURE PAYOUTS UNDER NON-EQUITY INCENTIVE PLAN AWARDS[(1)]			ESTIMATED FUTURE PAYOUTS UNDER EQUITY INCENTIVE PLAN AWARDS[(2)]			ALL OTHER STOCK AWARDS: NUMBER OF SHARES OF STOCK OR UNITS (#)	ALL OTHER OPTION AWARDS: NUMBER OF SECURITIES UNDERLYING OPTIONS[(3)] (#)	EXERCISE OR BASE PRICE OF OPTION AWARDS ($/SH)	GRANT DATE FAIR VALUE OF STOCK AND OPTION AWARDS[(4)] ($)
NAME	GRANT DATE	THRESHOLD ($)	TARGET ($)	MAXIMUM ($)	THRESHOLD (#)	TARGET (#)	MAXIMUM (#)				
John W. Ketchum	—	0	2,520,000	5,040,000	—	—	—	—	—	—	—
	2/15/2024				0	132,731	265,462				10,014,023
	2/15/2024				0	5,477	5,477				311,950
	2/15/2024								230,700	57.27	2,599,989
	2/20/2024				0	25,660	25,660				727,974
Brian W. Bolster	—	0	665,000	1,330,000	—	—	—	—	—	—	—
	5/6/2024				0	31,202	62,404				3,144,288
	5/6/2024				0	9,543	9,543				679,939
	5/6/2024				0	21,052	21,052				1,499,955
	5/6/2024								43,899	71.25	679,996
Rebecca J. Kujawa	—	0	1,100,000	2,200,000	—	—	—	—	—	—	—
	2/15/2024				0	80,109	160,218				6,043,904
	2/15/2024				0	15,435	15,435				883,962
	2/15/2024								120,674	57.27	1,359,996
	2/20/2024				0	16,778	16,778				475,992
Armando Pimentel, Jr.	—	0	1,000,000	2,000,000	—	—	—	—	—	—	—
	2/15/2024				0	70,685	141,370				5,332,901
	2/15/2024				0	20,953	20,953				1,199,978
	2/15/2024								106,477	57.27	1,199,996
Charles E. Sieving	—	0	892,000	1,784,000	—	—	—	—	—	—	—
	2/15/2024				0	30,031	60,062				2,265,719
	2/15/2024				0	5,786	5,786				331,364
	2/15/2024								45,244	57.27	509,900
	2/20/2024					6,291	6,291				178,476
Terrell Kirk Crews II	—	0	511,200	1,022,400	—	—	—	—	—	—	—
	2/15/2024				0	23,074	46,148				1,740,841
	2/15/2024				0	4,445	4,445				254,565
	2/15/2024								34,755	57.27	391,689
	2/20/2024				0	4,832	4,832				137,084

(1) Non-Equity Incentive Plan awards are paid under the Annual Incentive Plan, the material terms of which are described in Compensation Discussion & Analysis. For 2024, amounts payable were paid in cash in February 2025. See column (G) of *Table 1a: 2024 Summary Compensation Table* for actual amounts paid with respect to 2024 under the Annual Incentive Plan.

(2) In 2024, each NEO was granted awards of performance shares and performance-based restricted stock under the 2021 LTIP and, for

Mrs. Kujawa and Messrs. Ketchum, Crews and Sieving, performance-based restricted XPLR common units under the NEP 2014 LTIP. Performance shares were granted in 2024 for a three-year performance period ending December 31, 2026. The number of shares which will ultimately be paid to each NEO at the end of the performance period will be determined by multiplying the NEO's target number of performance shares by a percentage determined by the Compensation Committee based on the Company's performance over the three-year performance period (as more fully described in Compensation Discussion & Analysis), which may not exceed 200% of the target award. See footnotes (4) through (8) to *Table 3: 2024 Outstanding Equity Awards at Fiscal Year End* for further information about the vesting of performance-based restricted stock and performance-based restricted XPLR common units.

(3) Non-qualified stock options were granted under the 2021 LTIP in 2024. The stock options generally vest and become exercisable at the rate of one-third per year beginning approximately one year from date of grant and are fully exercisable after three years. See footnote (1) to *Table 3: 2024 Outstanding Equity Awards at Fiscal Year End* for further information about the vesting of stock options. All stock options were granted at an exercise price of 100% of the closing price of NextEra Energy common stock on the date of grant.

(4) The amounts shown are the value of the equity-based compensation grants as of the 2024 grant date under applicable accounting rules.

Additional disclosure related to 2024 summary compensation table and 2024 grants of plan-based awards table

<table>
<tr><th colspan="4">MATERIAL TERMS OF EQUITY GRANTS TO NEOS IN 2024</th></tr>
<tr><th>EQUITY TYPE</th><th>VESTING CONDITIONS</th><th>IMPACT OF TERMINATION</th><th>OTHER PROVISIONS</th></tr>
<tr><td>PERFORMANCE SHARES</td><td rowspan="2">May vest in full or in part upon the occurrence of certain events, such as a change in control, death, disability or some retirements</td><td rowspan="4">Forfeited if employment terminates prior to vesting, or prior to the end of the performance period, in all other instances (subject to terms of Retention Agreements and the Severance Plan)</td><td rowspan="4">Award agreements include non-solicitation and non-competition provisions</td></tr>
<tr><td>NON-QUALIFIED STOCK OPTIONS</td></tr>
<tr><td>PERFORMANCE-BASED RESTRICTED STOCK</td><td rowspan="2">May vest in full or in part prior to or on normal vesting date and, in some circumstances, without regard to satisfaction of performance objectives, upon the occurrence of certain events, such as a change in control, death, disability or some retirements</td></tr>
<tr><td>PERFORMANCE-BASED RESTRICTED XPLR COMMON UNITS</td></tr>
</table>

DETERMINATION OF AMOUNT PAYABLE UNDER ANNUAL INCENTIVE PLAN TO NEOS

See Compensation Discussion & Analysis for a description of the criteria used to determine the amount payable to each NEO under the Annual Incentive Plan (Non-Equity Incentive Plan Compensation).

Table 3: 2024 outstanding equity awards at fiscal year end

The following table provides information about equity incentive awards granted to the NEOs in 2024 and in prior years. It is important to keep in mind the following when reviewing the table:

» The number of shares listed in column (I), "Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested," includes both performance shares, at maximum payout level (in accordance with applicable SEC rules), prior to the expiration of the performance period, and performance-based restricted stock, performance-based restricted stock units and performance-based restricted XPLR common units prior to the satisfaction of the performance and time criteria required for vesting.

» As required by SEC rules, the amounts listed in column (J), "Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested," represent the value of performance-based restricted stock, performance-based restricted stock units and performance-based restricted XPLR common units and performance share awards at maximum payout levels. These amounts were not realized by the NEOs during 2024, and the value of awards which vest at a later date is likely to be different from the amount listed, based on, among other factors, the performance of the Company and the price of the Company's common stock.

TABLE 3: 2024 OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	OPTION AWARDS					STOCK AWARDS			
NAME	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS EXERCISABLE[1] (#)	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS UNEXERCISABLE[1][2] (#)	EQUITY INCENTIVE PLAN AWARDS: NUMBER OF SECURITIES UNDERLYING UNEXERCISED UNEARNED OPTIONS (#)	OPTION EXERCISE PRICE ($)	OPTION EXPIRATION DATE	NUMBER OF SHARES OR UNITS OF STOCK THAT HAVE NOT VESTED (#)	MARKET VALUE OF SHARES OR UNITS OF STOCK THAT HAVE NOT VESTED[3] ($)	EQUITY INCENTIVE PLAN AWARDS: NUMBER OF UNEARNED SHARES, UNITS OR OTHER RIGHTS THAT HAVE NOT VESTED[4] (#)	EQUITY INCENTIVE PLAN AWARDS: MARKET OR PAYOUT VALUE OF UNEARNED SHARES, UNITS OR OTHER RIGHTS THAT HAVE NOT VESTED[3] ($)
John W. Ketchum	75,068	0	0	27.92	2/12/2026				
	98,140	0	0	31.72	2/17/2027				
	90,768	0	0	38.61	2/15/2028				
	106,440	0	0	45.65	2/14/2029				
	89,972	0	0	68.87	2/13/2030				
	99,595	0	0	83.95	2/11/2031				
	139,420	69,710[5]	0	75.38	2/17/2032				
	57,585	115,172[6]	0	75.69	2/16/2033				
	0	230,700[7]	0	57.27	2/15/2034				
						—	—	458,770[9]	32,889,221[9]
						—	—	9,356[10]	670,732[10]
						—	—	65,516[11]	4,696,861[11]
						—	—	35,561[12]	632,986[12]
Brian W. Bolster	0	43,899[8]	0	71.25	5/6/2034				
						—	—	62,404[9]	4,473,743[9]
						—	—	30,595[10]	2,193,356[10]
Rebecca J. Kujawa	56,120	0	0	45.65	2/14/2029				
	51,396	0	0	68.87	2/13/2030				
	60,981	0	0	83.95	2/11/2031				
	70,108	35,054[5]	0	75.38	2/17/2032				
	30,121	60,244[6]	0	75.69	2/17/2033				
	0	120,674[7]	0	57.27	2/15/2034				
						—	—	276,888[9]	19,850,101[9]
						—	—	26,383[10]	1,891,397[10]
						—	—	65,516[11]	4,696,861[11]
						—	—	23,179[12]	412,586[12]
Armando Pimentel, Jr.	145,140	0	0	27.92	2/12/2026				
	157,464	0	0	31.72	2/17/2027				
	129,460	0	0	38.61	2/15/2028				
	20,840	0	0	45.65	2/14/2029				
	26,578	53,156[6]	0	75.69	2/16/2033				
	0	106,477[7]	0	57.27	2/15/2034				
						—	—	244,314[9]	17,514,871[9]
						—	—	31,523[10]	2,259,884[10]

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	OPTION AWARDS					STOCK AWARDS			
NAME	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS EXERCISABLE[1] (#)	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS UNEXERCISABLE[1][2] (#)	EQUITY INCENTIVE PLAN AWARDS: NUMBER OF SECURITIES UNDERLYING UNEXERCISED UNEARNED OPTIONS (#)	OPTION EXERCISE PRICE ($)	OPTION EXPIRATION DATE	NUMBER OF SHARES OR UNITS OF STOCK THAT HAVE NOT VESTED (#)	MARKET VALUE OF SHARES OR UNITS OF STOCK THAT HAVE NOT VESTED[3] ($)	EQUITY INCENTIVE PLAN AWARDS: NUMBER OF UNEARNED SHARES, UNITS OR OTHER RIGHTS THAT HAVE NOT VESTED[4] (#)	EQUITY INCENTIVE PLAN AWARDS: MARKET OR PAYOUT VALUE OF UNEARNED SHARES, UNITS OR OTHER RIGHTS THAT HAVE NOT VESTED[3] ($)
Charles E. Sieving	67,100	0	0	45.65	2/14/2029				
	51,044	0	0	68.87	2/13/2030				
	43,846	0	0	83.95	2/11/2031				
	30,369	15,185[5]	0	75.38	2/17/2032				
	11,293	22,587[6]	0	75.69	2/16/2033				
	0	45,244[7]	0	57.27	2/15/2034				
						—	—	103,798[9]	7,441,279[9]
						—	—	10,074[10]	722,205[10]
						—	—	65,516[11]	4,696,861[11]
						—	—	8,797[12]	156,587[12]
T. Kirk Crews	5,612	0	0	31.72	2/17/2027				
	4,720	0	0	38.61	2/15/2028				
	9,340	0	0	45.65	2/14/2029				
	7,748	0	0	68.87	2/13/2030				
	6,123	0	0	83.95	2/11/2031				
	16,832	8,416[5]	0	75.38	2/17/2032				
	8,675	17,351[6]	0	75.69	2/16/2033				
	0	34,755[7]	0	57.27	2/15/2034				
						—	—	79,752[9]	5,717,421[9]
						—	—	7,446[10]	533,804[10]
						—	—	6,589[12]	117,284[12]

(1) All stock options are non-qualified. All options listed as exercisable at December 31, 2024 were fully vested at that date.

(2) Stock options vest one third per year on the anniversary of the grant date until they become fully vested on the third anniversary of the grant date.

(3) Market value of the performance shares, performance-based restricted stock and performance-based restricted stock units is based on the closing price of NextEra Energy common stock on December 31, 2024 of $71.69. Market value of the unvested performance-based restricted XPLR common units is based on the closing price of XPLR common units on December 31, 2024 of $17.80.

(4) Performance shares generally vest on the last day of the applicable performance period, with payouts determined by the Compensation Committee at its first regular meeting after the end of the year. Because the end of the performance period for the performance shares granted to each of the NEOs in 2022 was December 31, 2024, these performance shares are not included in *Table 3: 2024 Outstanding Equity Awards at Fiscal Year End* and are included in *Table 4: 2024 Option Exercises and Stock Vested* under columns (D) and (E), "Stock Awards — Number of Shares Acquired on Vesting" and "Stock Awards — Value Realized on Vesting," and discussed in footnote (1) to that table.

(5) Represents the balance of stock options granted on February 17, 2022, which vested February 15, 2025.

(6) Represents stock options granted on February 16, 2023, one-half of which vested February 15, 2025 and the remaining one-half will vest on February 15, 2026.

(7) Represents stock options granted on February 15, 2024, one-third of which vested on February 15, 2025 and the remainder of which vests in equal annual installments on February 15, 2026 and February 15, 2027.

(8) Represents stock options granted on May 6, 2024, one-third of which will vest on May 6, 2025 and the remainder of which vests in equal annual installments on May 6, 2026 and May 6, 2027.

(9) The amount shown represents performance shares of NextEra Energy stock counted at the maximum payout of 200%. For Mr. Ketchum, the original number of shares granted was 96,654 and 132,731, which vest on 12/31/2025 and 12/31/2026, respectively. For Mr. Bolster, the original number of shares granted was 31,202, which vest on 12/31/2026. For Mrs. Kujawa, the original number of shares granted was 58,335 and 80,109, which vest on 12/31/2025 and 12/31/2026, respectively. For Mr. Pimentel, the original number of shares granted was 51,472 and 70,685, which vest on 12/31/2025 and 12/31/2026, respectively. For Mr. Sieving, the original number of shares granted was

21,868 and 30,031, which vest on 12/31/2025 and 12/31/2026, respectively. For Mr. Crews, the original number of shares granted was 16,802 and 23,074, which vest on 12/31/2025 and 12/31/2026, respectively

(10) The amount shown represents performance-based restricted stock of NextEra Energy. For Mr. Ketchum, the number of shares vesting is as follows: 4,350 on 2/15/2025, 3,190 on 2/15/2026 and 1,816 on 2/15/2027. For Mr. Bolster, the number of shares vesting is as follows: 3,181 on 5/6/2025, 3,181 on 5/6/2026 and 24,233 on 5/6/2027. For Mrs. Kujawa, the number of shares vesting is as follows: 12,200 on 2/15/2025, 9,038 on 2/15/2026 and 5,145 on 2/15/2027. For Mr. Pimentel, the number of shares vesting is as follows: 12,269 on 2/15/2025, 12,269 on 2/15/2026 and 6,985 on 2/15/2027. For Mr. Sieving, the number of shares vesting is as follows: 4,756 on 2/15/2025, 3,389 on 2/15/2026 and 1,929 on 2/15/2027. For Mr. Crews, the number of shares vesting is as follows: 3,361 on 2/15/2025, 2,603 on 2/15/2026 and 1,482 on 2/15/2027.

(11) The amount shown represents shares of performance-based restricted NextEra Energy stock units (including shares added to the award upon the reinvestment of dividend equivalents), granted 2/11/2021 pursuant to a one-time executive transition award. For Messrs. Ketchum and Sieving, and Mrs. Kujawa, the number of shares vesting is 32,758 on 2/15/2026 and 32,759 on 2/15/2031.

(12) The amount shown represents performance-based restricted XPLR common units. For Mr. Ketchum, the number of units vesting is as follows: 14,938 on 2/15/2025, 12,069 on 2/15/2026, and 8,554 on 2/15/2027. For Mrs. Kujawa, the number of units vesting is as follows: 9,694 on 2/15/2025, 7,892 on 2/15/2026, and 5,593 on 2/15/2027. For Mr. Sieving, the number of units vesting is as follows: 3,741 on 2/15/2025, 2,959 on 2/15/2026, and 2,097 on 2/15/2027. For Mr. Crews, the number of units vesting is as follows: 2,705 on 2/15/2025, 2,273 on 2/15/2026, and 1,611 on 2/15/2027.

Table 4: 2024 option exercises and stock vested

The following table provides information about the NEOs' stock awards which vested in 2024. It is important to keep in mind the following when reviewing the table:

- The "Number of Shares Acquired on Vesting" (column (D)) represents performance shares granted in 2022 for the performance period which ended in 2024, as well as performance-based restricted stock vesting in 2024 from grants made in prior years. The Compensation Committee looks at the value of these grants as of the date of grant, rather than as of the date of vesting, when making compensation determinations.
- The "Value Realized on Vesting" (column (E)) represents the aggregate payout value of the vested performance shares and vested performance-based restricted stock.

TABLE 4: 2024 OPTION EXERCISES AND STOCK VESTED

(A)	(B)	(C)	(D)	(E)
	OPTION AWARDS		STOCK AWARDS	
NAME	NUMBER OF SHARES ACQUIRED ON EXERCISE (#)	VALUE REALIZED ON EXERCISE ($)	NUMBER OF SHARES ACQUIRED ON VESTING[1] (#)	VALUE REALIZED ON VESTING[1] ($)
John W. Ketchum	0	0	141,432	9,330,188
Brian W. Bolster	0	0	0	0
Rebecca J. Kujawa	0	0	88,170	5,750,565
Armando Pimentel, Jr.	99,412	5,377,692	5,284	302,615
Charles E. Sieving	67,588	2,934,276	38,526	2,506,692
Terrell Kirk Crews II	0	0	21,485	1,399,132

(1) Includes:

NAME	NUMBER OF PERFORMANCE-BASED RESTRICTED NEE STOCK #	VALUE $	NUMBER OF PERFORMANCE-BASED RESTRICTED XPLR COMMON UNITS #	VALUE $	NUMBER OF PERFORMANCE SHARES (#)	VALUE ($)
John W. Ketchum	5,074	290,588	7,819	221,825	128,539	8,817,775
Brian W. Bolster	0	0	0	0	0	0
Rebecca J. Kujawa	8,610	493,095	4,980	141,283	74,580	5,116,188
Armando Pimentel, Jr.	5,284	302,615	0	0	0	0
Charles E. Sieving	3,946	225,987	2,274	64,513	32,306	2,216,192
Terrell Kirk Crews II	2,396	137,219	1,183	33,562	17,906	1,228,352

Table 5: Pension benefits

The table and description below provide information about the NEOs' pension benefits. It is important to keep in mind the "Present Value of Accumulated Benefit" (column (D)) listed for the SERP includes the present value of such benefits in the defined benefit portion of the SERP only, and disclosure of information related to the defined contribution portion of the SERP can be found in the next table, Table 6: Non-qualified Deferred Compensation.

(A)	(B)	(C)	(D)	(E)
NAME	PLAN NAME	NUMBER OF YEARS CREDITED SERVICE (#)	PRESENT VALUE OF ACCUMULATED BENEFIT ($)	PAYMENTS DURING LAST FISCAL YEAR($)
John W. Ketchum(1)	NextEra Energy, Inc. Employee Pension Plan	22	466,576	0
	SERP(3)	22	3,682,003	0
Brian W. Bolster(1)	NextEra Energy, Inc. Employee Pension Plan	1	0	0
	SERP(3)	1	0	0
Rebecca J. Kujawa(1)	NextEra Energy, Inc. Employee Pension Plan	18	343,765	0
	SERP(3)	18	1,574,621	0
Armando Pimentel, Jr.(1)	NextEra Energy, Inc. Employee Pension Plan	13	286,145	0
	SERP(2)(3)	13	414,252	0
Charles E. Sieving(1)	NextEra Energy, Inc. Employee Pension Plan	16	322,940	0
	SERP(3)	16	3,468,148	0
Terrell Kirk Crews II(1)	NextEra Energy, Inc. Employee Pension Plan	9	147,469	0
	SERP(3)	9	589,012	0

(1) For Mrs. Kujawa and Messrs. Ketchum, Bolster, Pimentel, Sieving and Crews the amounts shown are their respective accrued pension benefits as of December 31, 2024, which are equal to their respective cash balance account values in the tax qualified employee pension plan and in the SERP at December 31, 2024. Mrs. Kujawa and Messrs. Ketchum, Pimentel, Sieving and Crews are fully vested in both plans. Each NEO is entitled to his or her fully vested accrued account balances upon termination of employment.

(2) Mr. Pimentel's years of credited service include the years of prior service prior to rejoining the Company; he did not receive a SERP enhancement.

(3) NextEra Energy's non-qualified SERP provides both defined benefit and defined contribution benefits. See Additional Disclosure Related to Pension Benefits Table, below. The defined benefit portion of the SERP is shown in this table, while amounts attributable to the defined contribution portion of the SERP are included in *Table 1a: 2024 Summary Compensation Table* under column (I), "All Other Compensation" (amounts for which are detailed in *Table 1b: 2024 Supplemental All Other Compensation*), and also are reported in *Table 6: Non-qualified Deferred Compensation* under columns (C), (D) and (F).

Additional disclosure related to pension benefits table

NextEra Energy maintains two non-contributory defined benefit retirement plans: a tax-qualified employee pension plan and a non-qualified SERP.

EMPLOYEE PENSION PLAN

NextEra Energy's tax-qualified employee pension plan is a cash balance plan in which credits to each active, full-time employee's account are determined as a percentage of his or her monthly covered earnings, with "basic crediting" of 4.5% until the fifth anniversary of employment and 6% thereafter. Covered earnings for each NEO are limited to base salary and do not include annual incentive compensation, long-term incentive compensation or any other compensation included in *Table 1a: 2024 Summary Compensation Table*. Each employee's cash balance account is also credited quarterly with interest at an annual rate equal to the average rates of interest paid on one-year Treasury Constant Maturities for the month of August of the preceding calendar year. The interest crediting rate is subject to a 3% minimum for account balances earned after 2014 and a 4% minimum for account balances earned prior to 2015 and to a 14% maximum. For 2024, the interest crediting rate was 5.37% for account balances earned prior to 2015 and 5.37% for account balances earned after 2014. Benefits under the cash balance formula are not reduced for employer contributions to Social Security or other offset amounts.

Under the tax-qualified employee pension plan, benefits are cliff-vested after three full years of service and employees may become fully vested if they are participants in the qualified plan at a time when the Company decides to transfer a portion of pension plan assets to fund retiree medical benefits. All NEOs, other than Mr. Bolster, are fully vested. All vested participants are eligible for lump sum payment of benefits following termination of employment, and certain annuity forms of payment also are available to all employees, including the NEOs.

SERP

For the reasons described in Compensation Discussion & Analysis, NextEra Energy maintains an unfunded SERP for its executive officers, including the NEOs. The SERP's defined benefit formula for NEOs provides two times the normal cash balance crediting rate of the tax-qualified employee pension plan ("Double Basic Credits"). Also for the SERP, the Double Basic Credits are applied to base salary plus bonus paid during the year (versus base salary only). The normal cash balance crediting rate is 4.5% of base salary prior to five years of service and 6% of base salary thereafter. Double the basic crediting rate is therefore 9% and 12% of base salary plus bonus paid during the year for the SERP. Benefits for all NEOs are calculated in this manner.

SERP benefits are cliff-vested after five full years of total service and all NEOs, with the exception of Mr. Bolster, were fully vested as of December 31, 2024. All vested participants are eligible for lump sum payment of benefits following termination of employment (subject to timing restrictions imposed by section 409A of the Code) or may elect certain annuity forms of payment.

Table 6: Non-qualified deferred compensation

The table and description below provide information about the NEOs' non-qualified deferred compensation. It is important to keep in mind the following when reviewing the table:

» The amounts shown under the heading "Aggregate Earnings in Last FY" (column (D)) represent earnings in the Deferred Compensation Plan, in the defined contribution portion of the SERP.

» The amounts shown under the heading "Aggregate Balance at Last FYE" (column (F)) represent balances in the Deferred Compensation Plan and in the defined contribution portion of the SERP.

TABLE 6: NON-QUALIFIED DEFERRED COMPENSATION

(A)	(B)	(C)	(D)	(E)	(F)
NAME	EXECUTIVE CONTRIBUTIONS IN LAST FY(1) ($)	REGISTRANT CONTRIBUTIONS IN LAST FY(2) ($)	AGGREGATE EARNINGS IN LAST FY(3) ($)	AGGREGATE WITHDRAWALS/ DISTRIBUTIONS ($)	AGGREGATE BALANCE AT LAST FYE(4) ($)
John W. Ketchum	0	278,673	330,487	0	2,015,993
Brian W. Bolster	0	17,684	1,785	0	19,469
Rebecca J. Kujawa	0	132,003	102,779	0	650,322
Armando Pimentel, Jr.	0	118,513	17,417	0	159,587
Charles E. Sieving	0	122,104	436,351	0	2,584,070
Terrell Kirk Crews II	0	62,981	64,458	0	397,603

(1) The Deferred Compensation Plan permits deferral (up to 100%) of salary, annual incentive and performance shares.

(2) The SERP includes a defined contribution component which provides a match on NEOs' base and annual incentive earnings above the IRS limit, which was $345,000 for 2024. The 4.75% match is the same as the match opportunity provided to participants in the Company's 401(k) plan. As with the 401(k) plan, crediting of matching contributions under the defined contribution component of the SERP is in the form of phantom NextEra Energy common stock. All amounts shown in this column also are included in *Table 1a: 2024 Summary Compensation Table* in column (I), "All Other Compensation" (amounts for which are detailed in *Table 1b: 2024 Supplemental All Other Compensation*).

(3) Earnings include the sum of each participant's annual earnings (which includes, among other things, stock price appreciation on stock-based deferred compensation) in the Deferred Compensation Plan and in the defined contribution portion of the SERP. Earnings include Deferred Compensation Plan earnings of $12,540 for Mr. Sieving. Mrs. Kujawa and Messrs. Ketchum, Bolster, Crews and Pimentel have not deferred any compensation under this plan. Earnings for the defined contribution component of the SERP were as follows: Mr. Ketchum $330,487, Mr. Bolster $1,785, Mrs. Kujawa $102,779, Mr. Pimentel $17,417, Mr. Sieving $436,351 and Mr. Crews $64,458. None of these amounts are included in *Table 1a: 2024 Summary Compensation Table* since no above-market interest was credited in 2024.

(4) Deferred Compensation Plan accounts include fully vested and earned compensation plus earnings. The Company views deferred compensation as a vehicle for retirement planning rather than as a means of providing additional compensation. Mr. Sieving had a Deferred Compensation Plan balance of $119,221. Mrs. Kujawa and Messrs. Ketchum, Bolster, Crews and Pimentel have not deferred any cash compensation or performance shares and therefore have no balances in the Deferred Compensation Plan. Balances for the defined contribution component of the SERP were as follows: Mr. Ketchum $2,015,993 (of which $908,168 was previously reported as compensation in prior Summary Compensation Tables for years prior to 2024), Mr. Bolster $19,469 (of which $0 was previously reported as compensation in prior Summary Compensation Tables for years prior to 2024), Mrs. Kujawa $650,322 (of which $375,694 was previously reported as compensation in prior Summary Compensation Tables for the years prior to 2024), Mr. Pimentel $159,587 (of which $26,892 was previously reported as compensation in prior Summary Compensation Tables for years prior to 2024), Mr. Sieving $2,584,070 (of which $591,039

was previously reported in prior Summary Compensation Tables for years prior to 2024), Mr. Crews $397,603 (of which $98,298 was previously reported as compensation in prior Summary Compensation Tables for years prior to 2024).

Additional disclosure related to non-qualified deferred compensation table

Cash deferral elections under the Deferred Compensation Plan must be made prior to the period in which the cash is earned and can range, in whole percentages, from 1% to 100% of a participant's base salary and/or annual incentive award. Equity deferral elections must be made by December 31 of the year preceding the beginning of the applicable performance period, and participants electing to defer performance shares may defer all or a portion of the payout amount. Deferred Compensation Plan earnings are not guaranteed by the Company.

The Company's contributions to the SERP for each NEO also are considered deferred compensation. The contributions and earnings in *Table 6: Non-qualified Deferred Compensation* include those from the non-qualified defined contribution portion of the SERP. Distributions are in the form of lump sum payments, which may be subject to a six-month delay following termination of employment in compliance with Code Section 409A.

Earnings in 2024 from previous deferrals of cash compensation came from phantom investments in the investment vehicles, which mirror the funds available to participants in the Company's 401(k) plan and include mutual funds, index funds and similar investment alternatives offered to participants under the Company's 401(k) plan. The Company does not provide a guaranteed rate of return on these funds.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

For the reasons discussed in Compensation Discussion & Analysis, NextEra Energy has entered into the Retention Agreements, which commit the Company to make payments to NEOs under special circumstances. Generally, these are changes in corporate control of the Company and termination of the NEO's employment.

In accordance with SEC instructions, these quantitative disclosures assume a change in control took place on December 31, 2024. In fact, no change in control of the Company occurred on that date and no NEO's employment terminated on that date. If such an event were to occur in the future, actual payments would likely be different from those presented here based on various factors, including the NextEra Energy common stock price at such time.

Consistent with SEC instructions, the amounts shown in the tables that follow exclude obligations due from the Company to the NEO following a triggering event for:

(1) any earned but unpaid base salary, annual incentive compensation and long-term incentive compensation through the date of termination;

(2) vested benefits under the Company's employee pension and 401(k) plans and all other benefit plans in accordance with their terms and conditions;

(3) accrued vacation pay;

(4) reimbursement of reasonable business expenses incurred prior to the date of termination; and

(5) any other compensation or benefits to which the NEO may be entitled under and in accordance with the Company's generally applicable non-discriminatory plans or employee benefit programs, including the retiree medical plan.

Furthermore, all payments shown in the tables exclude the obligations of the Company to the NEO for vested benefits under the SERP and the Deferred Compensation Plan. See *Table 5: Pension Benefits and Table 6: Non-qualified Deferred Compensation* for the values of accumulated SERP and Deferred Compensation Plan benefits at December 31, 2024.

Potential payments under retention agreements

Each NEO is a party to a Retention Agreement with the Company. These agreements generally provide for certain protections and benefits to the NEO in the event of a change in control of the Company in exchange for the NEO's continued full-time commitment to the interests of the Company during a transition period of three years following a change in control. The NEOs also undertake confidentiality commitments requiring them to hold in a fiduciary capacity all secret or confidential information relating to the Company and, under most circumstances, not to divulge any such information either during or after the period of employment.

Each Retention Agreement provides for a mutual commitment to the NEO's continued employment for a period of three years following a change in control of the Company. If a change in control occurs, absent a termination of employment, the NEOs, other than Mr. Bolster, Mr. Crews and Mr. Pimentel, generally will receive an accelerated payout or vesting of previously granted equity-based awards the NEO would otherwise have received in the normal course of business had the change in control not occurred and had the NEO's employment continued over the remaining vesting periods. Mr. Bolster, Mr. Crews and Mr. Pimentel will receive an accelerated payout or vesting of previously granted equity-based awards following a change in control and termination of employment.

Tables 7a and *7b* and the accompanying discussion of the Retention Agreements set forth the details of the estimated payments that would have been made to the NEOs (on December 31, 2024 and December 31, 2025, respectively) had a change in control actually occurred at the close of business on December 31, 2024, assuming each of the NEOs continued in employment throughout 2024.

TABLE 7A: POTENTIAL COMPENSATION TO NAMED EXECUTIVES UPON CHANGE IN CONTROL

PAYMENT TYPE	JOHN W. KETCHUM ($)	BRIAN W. BOLSTER(5) ($)	REBECCA J. KUJAWA ($)	ARMANDO PIMENTEL, JR.(5) ($)	CHARLES E. SIEVING ($)	TERRELL KIRK CREWS II(5) ($)
Long-Term Incentive Awards:						
1st 50% of Performance Share Awards(1)	15,375,778	0	9,280,056	0	3,478,865	0
Restricted Stock and XPLR Common Unit Awards(2)(3)	1,303,717	0	2,303,983	0	878,792	0
Stock Option Awards(4)	3,326,694	0	1,740,119	0	652,418	0
Total	20,006,189	0	13,324,159	0	5,010,075	0

(1) Upon a change in control, 50% of all outstanding performance share awards vest and are payable at the greater of target or the average of the actual performance factors used to determine payout of performance share awards which vested over the three years prior to the year in which the change in control occurred, except for Mr. Bolster's, Mr. Pimentel's and Mr. Crews' awards. Amounts shown are based on a closing NextEra Energy common stock price on December 31, 2024 of $71.69 and performance factors are calculated based on actual performance for the three completed three-year performance periods preceding the year in which the change in control is assumed to have occurred. Amounts shown include the value of the acceleration of 50% of the performance shares awarded for the three-year performance periods ending December 31, 2025 and December 31, 2026. At the assumed change in control date, no performance shares had been awarded for the performance period ending December 31, 2027.

(2) Upon a change in control, all outstanding performance-based restricted stock and XPLR common unit awards vest, except for Mr. Bolster's, Mr. Pimentel's and Mr. Crews' awards. Amounts shown are based on a closing NextEra Energy common stock price on December 31, 2024 of $71.69 and a XPLR common unit price on December 31, 2024 of $17.80.

(3) The award agreement pursuant to which Mrs. Kujawa and Messrs. Ketchum and Sieving were each awarded an executive transition award of performance-based restricted stock units contains change in control provisions which supersede the provisions of the Retention Agreement for that award only. Upon a change in control, absent termination of employment, the executive transition award does not vest on an accelerated basis.

(4) Upon a change in control, all outstanding stock option awards vest, except for Mr. Bolster's, Mr. Pimentel's and Mr. Crews' awards. Amounts shown reflect the in-the-money values of accelerated stock options based on the difference between the option exercise price and the closing NextEra Energy common stock price on December 31, 2024 of $71.69.

(5) Per the terms of Mr. Bolster, Mr. Pimentel and Mr. Crews' Retention Agreements, their long-term incentive awards do not vest upon a change in control absent termination of employment.

TABLE 7B: POTENTIAL COMPENSATION TO NAMED EXECUTIVES AT ONE-YEAR ANNIVERSARY OF CHANGE IN CONTROL(1)

PAYMENT TYPE	JOHN W. KETCHUM ($)	BRIAN W. BOLSTER ($)	REBECCA J. KUJAWA ($)	ARMANDO PIMENTEL, JR. ($)	CHARLES E. SIEVING ($)	TERRELL KIRK CREWS II ($)
Long-Term Incentive Awards:						
2nd 50% of Performance Share Awards(2)	15,375,644	0	9,279,788	0	3,478,731	0

(1) All amounts in the table assume the same $71.69 stock price on the one-year anniversary of the assumed change in control.

(2) Each NEO, except for Mr. Bolster, Mr. Pimentel and Mr. Crews, is entitled to receive the remaining 50% of their outstanding performance share awards on the first anniversary of the change in control if the NEO has remained employed by the Company or an affiliate through such date, or upon an earlier termination of employment by the Company (except for death, disability or cause (which generally means repeated willful violations of the NEO's duties under their Retention Agreement or a felony conviction involving an act at the Company's expense)) or by the NEO for "good reason" (which generally includes the assignment of duties and responsibilities that are materially inconsistent with those in effect during the 90-day period immediately preceding the change in control, material decreases in compensation or benefits after the change in control, or change in job location of more than 20 miles). Amounts shown are based on performance factors calculated based on actual performance for the three completed three-year performance periods preceding the year in which the change in control occurred. Amounts shown include the value of the acceleration of 50% of the performance shares awarded for the three-year performance periods ending December 31, 2025 and December 31, 2026. At the assumed change in control date, no performance shares had been awarded for the performance period ending December 31, 2027. Amounts shown in the table are due to the NEO under such circumstances in addition to the amounts shown in *Table 7a: Potential Compensation to Named Executives Upon Change in Control*.

The amounts shown in *Tables 7a* and *7b* represent the accelerated payment of compensation the NEOs would otherwise have received over time absent a change in control, assuming continued employment. The employment protection amounts represent additional payments and are intended both to compensate the NEO for the lost opportunity of continued employment and to encourage the new leadership of the post-change-in-control entity to evaluate carefully the desirability of terminating the NEO's employment as opposed to seeking an appropriate role for the NEO in the new entity.

The Retention Agreements are designed to provide the NEOs with economic value in the event of termination equivalent to three years' worth of foregone base salary, annual incentive compensation and incremental retirement contributions. In addition, if termination by the Company for reasons other than death, disability or cause, or by the NEO for good reason, were to occur prior to the first anniversary of the change in control, the acceleration of the then-outstanding performance shares, as shown in *Table 7b*, would also occur. Because of this intent, the Retention Agreement in effect as of December 31, 2024 for Mr. Sieving provides for the additional payment by the Company of any excise tax imposed by section 4999 of the Code. However, if the total value of all payments due (calculated as required under section 280G of the Code) does not exceed 110% of the "safe harbor amount" under section 280G, or 2.99 times Mr. Sieving's five-year average W-2 earnings, then no gross-up payment will be made to Mr. Sieving and the amounts payable under the Retention Agreement will be reduced to the "safe harbor amount." In accordance with the Company's Excise Tax Gross-Up Policy, which generally precludes the inclusion of excise tax gross-up provisions in Retention Agreements entered into, or materially modified, after December 2009, Mrs. Kujawa's and Messrs. Ketchum's, Bolster's, Pimentel's and Crews' Retention Agreements do not include excise tax gross-up provisions. The NEO remains responsible for normal federal, state and local tax liability on the underlying economic value transferred.

If a change in control had occurred on December 31, 2024 and if any or all of the NEOs had been terminated on that date, the Company estimates the amounts shown in *Table 8* would have become payable.

TABLE 8: POTENTIAL POST-EMPLOYMENT COMPENSATION TO NAMED EXECUTIVES UPON TERMINATION WITHOUT CAUSE OR FOR GOOD REASON FOLLOWING CHANGE IN CONTROL[1]

PAYMENT TYPE	JOHN W. KETCHUM ($)	BRIAN W. BOLSTER ($)	REBECCA J. KUJAWA ($)	ARMANDO PIMENTEL, JR. ($)	CHARLES E. SIEVING ($)	TERRELL KIRK CREWS II ($)
Cash Severance[2]	16,301,250	4,845,000	9,075,000	8,520,000	8,525,067	4,710,435
Long-Term Incentive Awards[3]	35,381,833	6,395,621	22,603,947	20,171,686	8,488,806	6,555,218
Executive Transition Awards[4]	2,348,421	—	2,348,421	—	2,348,421	—
Incremental Increase in Non-qualified SERP[5]	3,604,476	0	1,953,112	0	2,238,644	0
Continued Participation in Active Employee Welfare Benefits[6]	289,878	137,338	147,462	73,214	173,554	85,738
Continued Participation in Certain Perquisite Programs[7]	168,710	75,000	152,400	83,640	173,890	75,000
Certain Limited Outplacement and Relocation Allowances[8]	48,750	23,750	48,750	23,750	48,750	23,750
Code Section 280G Gross-up (Cutback)[9]	0	0	0	(1,378,414)	0	0
Total	58,143,318	11,476,709	36,329,092	27,493,876	21,997,132	11,450,141

(1) All amounts in the table assume the same $71.69 stock price on the one-year anniversary of the assumed change in control.

(2) The amount shown represents the value of a cash lump sum payment due within 45 days of termination (subject to the requirements of section 409A of the Code) equal to three times the sum of the NEO's annual base salary plus his or her annual incentive. The annual incentive is equal to the higher of target annual incentive in the year of termination or the average percentage of the NEO's annual incentive divided by his or her base salary for each of the three years prior to the year in which the change in control occurred. Since all annual incentive compensation for 2024 was earned on December 31, 2024, no prorated amounts of 2024 annual incentive compensation are included.

(3) Includes 100% vesting of outstanding NEE performance-based restricted stock awards, XPLR performance-based restricted common units and stock option awards granted in 2022, 2023 and 2024. For Mrs. Kujawa and Messrs. Ketchum and Sieving, includes 100% of outstanding 2023 and 2024 performance share grants, with 50% payable upon a change in control and the remaining 50% would be payable on the one-year anniversary. For Mr. Crews and Mr. Pimentel, 100% of outstanding 2023 and 2024 performance shares would be payable upon a change in control. For Mr. Bolster, 100% of outstanding 2024 performance shares would be payable upon a change in control. Outstanding performance share awards vest and are payable at the greater of target or the average of the actual performance factors used to determine payout of performance share awards which vested over the three years prior to the year in which the change in control occurred.

(4) Under Mrs. Kujawa's and Messrs. Ketchum's and Sieving's executive transition award agreements, if discharged without cause or resigned for good reason upon or after a change in control, then a portion of the outstanding unvested executive transition award (including

reinvested dividends) would vest according to the schedule contained in the award agreement. If such termination had occurred on December 31, 2024 under these circumstances, the vesting percentage would have been 50% of the total award granted in 2021 for Mrs. Kujawa and Messrs. Ketchum and Sieving. Amounts shown are based on the closing NextEra Energy common stock price on December 31, 2024 of $71.69.

(5) For Mrs. Kujawa, Mr. Ketchum and Mr. Sieving, the amount shown represents the value of a cash lump sum payment due within 45 days of termination (subject to the requirements of Code section 409A) equal to the incremental increase in value of the NEO's non-qualified SERP benefits under the defined benefit and defined contribution formulas if the NEO had continued employment for three years from the date of termination, and assuming the NEO received the annual compensation increases required under the Retention Agreement for the three-year or two-year employment period. For Messrs. Bolster, Pimentel and Crews, their Retention Agreements do not include this incremental increase.

(6) The Retention Agreements provide for continued coverage under all employee benefit plans for three years. Plans include the broad-based employee medical plan, the broad-based employee dental plan, short-term and long-term disability insurance and the broad-based employee life insurance plan. Amounts shown represent three-year employer costs based on December 31, 2024 rates (plus, for employee medical and dental coverage, projected average annual cost increase of 5.3% and increase of 2.3%, respectively). For long-term disability, the estimated total actuarial liability is equal to the approximate cost of insuring the liability for the severance period. These amounts assume no offsets for benefits provided by a subsequent employer. The amount set forth on this line is also payable to the NEO or his or her beneficiaries if the NEO dies or becomes disabled during the employment period following a change in control.

(7) The Retention Agreements provide for continued participation in certain other benefits and perquisites for three years. Amounts shown include: participation in the executive vehicle program (or, for Mrs. Kujawa and Messrs. Bolster, Pimentel and Crews, annual perquisite allowance in lieu of executive vehicle program); personal financial planning, accounting and legal services; personal communication and computer equipment; home security, including monitoring and maintenance; and personal excess liability insurance. The Retention Agreements do not provide for use of Company-owned aircraft. The amount shown for each NEO represents the Company's approximate three-year costs for providing such perquisites to the NEO, based on 2024 and prior years' actual costs.

(8) Includes an aggregate cost per NEO of $23,750 for outplacement services, fees for legal or accounting advice related to tax treatment of certain payments under the Retention Agreements and reimbursement for miscellaneous relocation expenses incurred by the NEO in pursuing other business opportunities which are not reimbursed by another employer. Such reimbursements are required under the Retention Agreements.

(9) For Mr. Sieving, the aggregate payment due (calculated as required under section 280G of the Code) does not exceed 110% of the "safe harbor amount" under section 280G, or 2.99 times his five-year average W-2 earnings and, therefore, no gross-up payment will be made and the amount payable under the Retention Agreement will be reduced to the "safe harbor amount." Mrs. Kujawa's and Messrs. Ketchum's, Bolster's, Pimentel's and Crews' Retention Agreements do not provide for excise tax gross-ups. The aggregate payment due to Mr. Pimentel exceeds the "safe harbor amount" under section 280G of the Internal Revenue Code, and, in accordance with Mr. Pimentel's Retention Agreement, the amounts payable to Mr. Pimentel would be reduced by the indicated amount to the "safe harbor amount." The aggregate payment due to each of Mrs. Kujawa and Mr. Ketchum does not exceed such NEO's "safe harbor amount." With the exception of a portion of accelerated stock option awards, the aggregate change in control-related compensation and benefit amount in excess of the NEO's "base amount" is considered an "excess parachute payment" and is subject to an excise tax under section 4999 of the Code. In circumstances where the NEO is entitled to receive from the Company a lump sum cash gross-up payment, the payment would be in an amount such that the net gross-up payment (after federal, state and local income and excise taxes and any penalties and interest are paid) is equal to the Code section 4999 excise tax. The 2024 annual incentive award and the performance share award for the performance period ended December 31, 2024 (payout values for which are included in *Table 1a: 2024 Summary Compensation Table* and in *Table 4: 2024 Option Exercises and Stock Vested*, respectively) were fully earned as of the assumed change in control date and are therefore not part of the "excess parachute payment" amount or the estimated gross-up amount.

Each Retention Agreement provides that a change in control occurs upon any of the following events:

(1) the acquisition by any individual, entity or group of 20% or more of either NextEra Energy's common stock or the combined voting power of NextEra Energy, other than directly from NextEra Energy or pursuant to a merger or other business combination which does not itself constitute a change in control;

(2) the incumbent directors of NextEra Energy ceasing, for any reason, to constitute a majority of the Board, unless each director who was not an incumbent director was elected, or nominated for election, by a majority of the incumbent directors and directors subsequently so elected or appointed (excluding those elected as a result of an actual or threatened election contest or other solicitation of proxies);

(3) there is consummated a merger, sale of assets, reorganization or other business combination of NextEra Energy or any subsidiary with respect to which (a) the voting securities of NextEra Energy outstanding immediately prior to the transaction do not, immediately following the transaction, represent more than 55% of the common stock and the voting power of all voting securities of the resulting ultimate parent entity or (b) members of the Board constitute less than a majority of the members of the Board of directors of the resulting ultimate parent entity; or

(4) the shareholders approve the liquidation or dissolution of NextEra Energy.

In addition, the Retention Agreements extend the NEOs' protection to certain potential change in control situations, which are:

(1) the announcement of an intention to take or consider taking actions which, if consummated or approved by shareholders, would constitute a change in control; or

(2) the acquisition by any individual, entity or group of 15% or more of either NextEra Energy's common stock or the

combined voting power of NextEra Energy, other than directly from NextEra Energy or pursuant to a merger or other business combination which does not itself constitute a change in control.

No accelerated or incremental payments are triggered by a potential change in control, but the NEO is protected for a three-year employment period.

Potential payments under the Severance Plan

The Severance Plan provides for the payment of severance benefits to the NEOs and to certain other senior executives if their employment is involuntarily terminated other than for Cause, defined below (and other than in a termination governed by the terms of the Retention Agreements). See Compensation Discussion & Analysis for a discussion of the purpose of the Severance Plan.

The Severance Plan provides severance benefits following involuntary termination other than for Cause in exchange for entry into a release of claims against the Company and an agreement (the "Non-Competition Agreement") to adhere to certain non-competition and related covenants protective of the Company. Following a covered involuntary termination and the execution of the release and the Non-Competition Agreement, the NEO would receive a cash payment equal to two times his or her annual base salary plus two times his or her target annual incentive compensation for the year of termination, payable in two equal annual installments. In addition, the NEO's outstanding equity and equity-based awards would vest pro rata and become payable at the end of any applicable performance periods, subject to the attainment by the Company of the specified performance objectives. The NEO also would receive certain ancillary benefits, including outplacement assistance or payment in an amount equal to the value of the outplacement assistance. Amounts payable under the Severance Plan are subject to a cap equal to six times the average of the NEO's last three years' base salary plus annual incentive.

If the employment of Mrs. Kujawa or Messrs. Ketchum, Bolster, Pimentel, Sieving or Crews, or any of them, had been involuntarily terminated on December 31, 2024 in circumstances triggering the Company's obligations under the Severance Plan, the Company estimates the amounts shown in *Table 9* below would have become payable.

TABLE 9: POTENTIAL POST-EMPLOYMENT COMPENSATION UPON TERMINATION QUALIFYING FOR PAYMENTS UNDER THE SEVERANCE PLAN

PAYMENT TYPE	JOHN W. KETCHUM ($)	BRIAN W. BOLSTER ($)	REBECCA J. KUJAWA ($)	ARMANDO PIMENTEL, JR. ($)	CHARLES E. SIEVING ($)	TERRELL KIRK CREWS II ($)
Cash Severance(1)	8,190,000	3,230,000	4,400,000	4,000,000	4,332,600	2,483,000
Long-Term Incentive Awards:						
Performance Share Awards(2)	7,791,200	745,580	4,702,360	4,149,060	1,762,710	1,354,370
Restricted Stock Awards(3)	831,420	602,980	1,497,730	1,394,660	575,760	419,180
Stock Option Awards(4)	1,778,690	19,320	930,380	820,920	348,810	267,940
Executive Transition Awards(5)	2,732,390	—	2,732,390	—	2,732,390	—
Certain Limited Outplacement and Other Perquisites(6)	35,000	35,000	35,000	35,000	35,000	35,000
Cutback Under Plan Benefit Cap(7)	0	0	0	0	0	0
Total	21,358,700	4,632,880	14,297,860	10,399,640	9,787,270	4,559,490

(1) The amount shown represents the value of a cash lump sum payment equal to two times the sum of the NEO's annual base salary plus his or her target annual incentive in effect on December 31, 2024.

(2) Upon a qualifying involuntary termination, a pro rata portion of outstanding performance share awards would continue to vest and would be paid based on the Company's actual level of achievement of the performance objectives at the conclusion of the performance period. Amounts shown include the value of the performance shares awarded for the three-year performance periods ending December 31, 2025 and December 31, 2026, respectively, based on the closing NextEra Energy common stock price on December 31, 2024 of $71.69. As the actual level of achievement of the performance objectives at the conclusion of the performance periods ending December 31, 2025 and December 31, 2026, respectively, would not have been known upon a hypothetical qualifying involuntary termination on December 31, 2024, amounts shown assume target, or 100%, performance. Actual payouts would be between 0% and 200% of target.

(3) Upon a qualifying involuntary termination, a pro rata portion of outstanding performance-based restricted stock and common unit awards would continue to vest, subject to the attainment of the applicable performance objective. Amounts shown assume the attainment of the performance objective and are based on the closing NextEra Energy common stock price on December 31, 2024 of $71.69 and XPLR common unit price on December 31, 2024 of $17.80.

(4) Upon a qualifying involuntary termination, outstanding stock option awards would vest on a pro rata basis. Amounts shown reflect the in-the-money values of the stock options that would vest based on the difference between the option exercise price and the closing NextEra Energy common stock price on December 31, 2024 of $71.69.

(5) Upon a qualifying involuntary termination, the outstanding unvested executive transition awards granted to Mrs. Kujawa and Messrs. Ketchum and Sieving would vest on a pro rata basis. Amounts shown are based on the closing NextEra Energy common stock price on December 31, 2024 of $71.69.

(6) Includes a maximum cost per NEO of $25,000 for providing outplacement services, plus the cost of financial planning, legal or accounting services.

(7) The total value of severance paid to each NEO is subject to a cap equal to six times the average of such NEO's last three years' base salary plus annual incentive.

Under the Severance Plan, an involuntary termination is defined as any of the following:

(1) the participant's termination by the Company or an affiliate without Cause (as described further below) and other than as a result of death or disability; or

(2) the participant's resignation after the occurrence of one or more of the following without the participant's consent:

  (i) the Company's material breach of a material provision of the Severance Plan or the Company's or an affiliate's material breach of a material provision of any other agreement between the participant and the Company or such affiliate;

  (ii) a relocation of participant's principal place of employment by more than 90 miles; or

  (iii) a material, adverse change in the participant's title, authority, duties or responsibilities with the Company or an affiliate, or any reduction in the participant's annual base salary or annual target cash incentive opportunity.

Cause is generally defined under the Severance Plan as any of the following:

(1) repeated violations by the participant of the participant's obligations to the Company or an affiliate that are willful and deliberate, which are committed in bad faith or without reasonable belief that the violations are in the Company's or an affiliate's best interests and that are not remedied within a reasonable period of time after the participant's receipt of written notice; or

(2) the participant's conviction of a felony.

The NEOs are required to comply with certain protective covenants, including two-year non-compete and non-solicitation provisions, in order to receive payments under the Severance Plan. Any severance payments would be subject to repayment and/or forfeiture if any of the protective covenants are violated.

Potential payments under Equity Award Agreements

The award agreements for each long term equity incentive award outstanding during 2024 (except the executive transition awards for Mrs. Kujawa and Messrs. Ketchum and Sieving, the terms of which are described below) contain provisions which govern treatment of the award in the event of the NEO's termination of employment due to death, disability, retirement at or after age 55 ("normal retirement"), or retirement after age 50 meeting terms and conditions set by, and acceptable to, the Compensation Committee (an "approved early retirement"). Under the terms of the equity award agreements (other than the executive transition awards), each outstanding unvested equity award vests on a pro rata basis for service through the date of death or disability or normal retirement (for performance share, stock option, performance-based restricted stock and performance-based restricted XPLR common unit awards based on days of service completed during the vesting period). The pro rata portion of each stock option, performance-based restricted stock and performance-based restricted XPLR common unit award is vested upon death or disability. In the case of normal retirement, stock option awards vest upon retirement and performance-based restricted stock and XPLR common units generally vest upon their normal vesting date following satisfaction of applicable performance criteria. The pro rata portion of each performance share award is paid after the end of the performance period, subject to satisfaction of applicable performance criteria. See *Table 3: 2024 Outstanding Equity Awards at Fiscal Year End* for information for each NEO as of December 31, 2024 about outstanding unvested equity awards which would vest as determined in the manner set forth above upon death, disability or normal retirement.

If an NEO was eligible for, and retired in accordance with, an approved early retirement, all outstanding and unvested equity awards (except the executive transition awards, as described below) would vest in full, and would be paid out either on the vesting schedule set forth in each award agreement or upon retirement, generally subject to satisfaction of applicable performance criteria.

The value of the prorated outstanding long-term incentive awards at December 31, 2024 for each of the NEOs would have been approximately: Mr. Ketchum, $10,401,310; Mr. Bolster $1,367,880; Mrs. Kujawa, $7,130,470; Mr. Pimentel, $6,364,640; Mr. Sieving, $2,687,280; and Mr. Crews, $2,041,490. As of December 31, 2024, each of Messrs. Ketchum, Pimentel and Sieving were of an age which would have made them eligible for consideration by the Compensation Committee for an approved early retirement. If the Compensation Committee had approved an early retirement for any of Messrs. Ketchum, Pimentel or Sieving on that date (which the Compensation Committee did not do), the value on December 31, 2024 of the outstanding long-term incentive awards that would have continued to vest on their original terms (performance shares and performance-based restricted stock and XPLR common units as applicable) or vested (options) would have been approximately: Mr. Ketchum, $21,075,020; Mr. Pimentel, $12,552,720; and Mr. Sieving, $5,251,850.

The award agreements governing the executive transition awards of Mrs. Kujawa and Messrs. Ketchum and Sieving provide for partial accelerated vesting of the stock and accrued dividends upon death or disability, according to a schedule contained in the award agreement. The award agreement does not provide for accelerated vesting upon retirement. If Mrs. Kujawa or Messrs. Ketchum or Sieving had terminated employment on December 31, 2024 due to death or disability, 50% of their total executive transition award granted in 2021 would have vested. The value of the unvested shares vesting solely due to death or disability would have been approximately $2,348,421. All equity award agreements (including the agreements governing the executive transition awards) include non-solicitation and non-competition provisions (effective during employment and for a two-year period after termination), as well as non-disparagement provisions. The terms of these protective covenants survive the termination of the award agreement and termination of employment.

PAY VERSUS PERFORMANCE (PVP)

Provided below is the Company's "Pay Versus Performance" disclosure as required pursuant to Item 402(v) of Regulation S-K. As required by Item 402(v), we have included:

- A tabular list of the most important measures our Compensation Committee used in 2024 to link pay calculated in accordance with Item 402(v) (referred to as "Compensation Actually Paid", or CAP) to Company performance;
- A table that compares the total compensation of our Named Executive Officers as presented in the *Summary Compensation Table* ("SCT") for each year to CAP and specified performance measures; and
- A discussion of:
  - the relationship between our cumulative TSR and the TSR of the S&P 500 Utilities Index ("Peer Group TSR");
  - the relationship between CAP and our TSR;
  - the relationship between CAP and our Net Income; and
  - the relationship between CAP and the Company's Adjusted EPS for each year, which is our Company Selected Measure ("CSM"). The CSM represents, in our assessment, the most important financial performance measure used to link CAP to Company performance.

This disclosure has been prepared in accordance with Item 402(v) and does not necessarily reflect value actually realized by our NEOs or how the Compensation Committee evaluates compensation decisions in light of Company or individual performance. In particular, the Compensation Committee does not use CAP as a basis for making compensation decisions. Please refer to our Compensation Discussion & Analysis on pages 35 to 83 for a discussion of our executive compensation program objectives and the ways in which we design our program to align executive compensation with Company performance.

Tabular list of most important measures to determine 2024 compensation actually paid

The list below represents the financial performance measures that the Company considers to have been the most important in linking CAP to our PEO and non-PEO NEOs for 2024 to Company performance. The measures are not ranked. Descriptions of these measures, and the manner in which these measures determine the amounts of incentive compensation paid to our NEOs, is described in our Compensation Discussion & Analysis within the sections titled "2024 Annual Performance-Based Incentive Compensation" and "2024 Long-Term Performance-Based Equity Compensation."

- Adjusted EPS
- Adjusted ROE
- Adjusted Earnings

Pay Versus Performance table

YEAR(1)	SUMMARY COMPENSATION TABLE TOTAL FOR FIRST PEO ($)	SUMMARY COMPENSATION TABLE TOTAL FOR SECOND PEO ($)	COMPENSATION ACTUALLY PAID TO FIRST PEO(2) ($)	COMPENSATION ACTUALLY PAID TO SECOND PEO(2) ($)	AVERAGE SUMMARY COMPENSATION TABLE TOTAL FOR NON-PEO NEOS ($)	AVERAGE COMPENSATION ACTUALLY PAID TO NON-PEO NEOS(2) ($)	VALUE OF INITIAL FIXED $100 INVESTMENT BASED ON: TOTAL SHAREHOLDER RETURN ($)	PEER GROUP TOTAL SHAREHOLDER RETURN(3) ($)	NET INCOME ($MMS)(4)	ADJUSTED EPS(5) ($)
(A)	(B)	(B)	(C)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2024	21,138,476	N/A	35,196,570	N/A	9,028,721	13,245,654	133.20	137.70	6,946	3.43
2023	20,591,124	N/A	7,211,720	N/A	8,470,154	3,917,791	109.62	107.78	6,282	3.17
2022	40,406,018	17,414,329	34,410,149	18,918,020	7,394,893	7,426,310	146.74	118.17	3,246	2.90
2021	25,335,936	N/A	55,348,220	N/A	13,316,860	19,729,777	160.51	118.24	2,827	2.55
2020	23,720,707	N/A	63,079,713	N/A	6,454,940	12,715,279	130.08	100.49	2,369	2.31

(1) During 2023 and 2024, our PEO was Mr. Ketchum. During 2022, our PEOs were James L. Robo (first PEO) and Mr. Ketchum (second PEO). During 2021 and 2020, our PEO was Mr. Robo. During 2024, our non-PEO NEOs consisted of Mr. Bolster, Mrs. Kujawa, Mr. Pimentel, Mr. Sieving and Mr. Crews. During 2023, our non-PEO NEOs consisted of Mr. Crews, Mrs. Kujawa, Mr. Pimentel and Mr. Sieving. During 2022, our non-PEO NEOs consisted of Mr. Crews, Mrs. Kujawa, Mr. Silagy, Mr. Sieving and Ms. Caplan. During 2021 and 2020, our non-PEO NEOs consisted of Messrs. Ketchum, Silagy and Sieving and Mrs. Kujawa.

(2) The following table sets forth the adjustments made during each year represented in the *PVP Table* to arrive at "compensation actually paid" during each year:

PEO and average non-PEO NEOs summary compensation table total to compensation actually paid reconciliation

YEAR	EXECUTIVE(S)	SUMMARY COMPENSATION TABLE TOTAL ($)	DEDUCT OPTION AND STOCK AWARDS GRANTED IN FISCAL YEAR ($)	ADD FAIR VALUE AT FISCAL YEAR-END OF UNVESTED OPTION AND STOCK AWARDS GRANTED IN FISCAL YEAR ($)	ADD CHANGE IN FAIR VALUE OF UNVESTED OPTION AND STOCK AWARDS GRANTED IN PRIOR FISCAL YEAR ($)	ADD CHANGE IN FAIR VALUE OF OPTION AND STOCK AWARDS VESTED IN FISCAL YEAR ($)	DEDUCT FAIR VALUE OF OPTION AND STOCK AWARDS FORFEITED IN FISCAL YEAR ($)	DEDUCT CHANGE IN PENSION VALUE AND NON-QUALIFIED DEFERRED COMPENSATION EARNINGS COLUMN OF THE SCT ($)	ADD PENSION SERVICE COST ($)	ADD DIVIDENDS PAID ON UNVESTED SHARES IN FISCAL YEAR ($)	COMPENSATION ACTUALLY PAID ($)(i)
2024	PEO	21,138,476	(13,653,936)	21,000,411	4,342,552	2,757,825	—	(918,853)	398,679	131,415	35,196,570
	Other NEOs	9,028,721	(5,662,109)	8,091,328	1,390,629	521,089	—	(313,148)	124,312	64,832	13,245,654
2023	PEO	20,591,124	(13,168,902)	9,993,852	(7,479,727)	(2,338,619)	—	(811,026)	352,471	72,547	7,211,720
	Other NEOs	8,470,154	(5,804,360)	4,172,741	(2,166,093)	(625,020)	—	(288,148)	120,554	37,962	3,917,791
2022	First PEO	40,406,018	(13,094,677)	18,259,934	(1,507,964)	(9,326,246)	—	(1,000,479)	597,194	76,368	34,410,149
	Second PEO	17,414,329	(10,623,931)	15,168,274	(1,053,175)	(1,857,707)	—	(475,209)	292,699	52,740	18,918,020
	Other NEOs	7,394,893	(4,332,201)	6,010,715	(554,750)	(1,002,574)	—	(305,362)	185,918	29,670	7,426,310
2021	First PEO	25,335,936	(17,391,104)	23,190,233	14,918,520	9,630,919	—	(1,023,668)	598,193	89,191	55,348,220
	Other NEOs	13,316,860	(9,961,104)	12,160,788	2,529,143	1,788,740	—	(375,214)	238,766	31,799	19,729,777
2020	First PEO	23,720,707	(16,101,809)	22,483,170	20,062,587	13,222,028	—	(951,970)	554,570	90,431	63,079,713
	Other NEOs	6,454,940	(3,495,669)	4,783,802	3,164,051	1,901,154	—	(316,805)	193,518	30,289	12,715,279

(i) Reflects the value of equity calculated in accordance with the SEC methodology for determining compensation actually paid, dividends paid in cash, and pension service cost for each year shown. The fair value of performance share awards was determined using the Monte-Carlo simulation process and the fair value of stock options was determined using the Black-Scholes pricing model. Compensation actually paid does not represent annual compensation realized.

(3) TSR is determined based on the value of an initial fixed investment of $100 and reflects reinvestment of dividends. The TSR peer group consists of the S&P 500 Utilities Index.

(4) Net income excludes net income attributable to non-controlling interests.

(5) See Appendix A for a reconciliation of adjusted EPS to the most directly comparable GAAP financial measure.

Over the last five years, our Company had robust financial and operational performance. Our TSR was slightly below the TSR of the S&P 500 Utilities Index; an initial investment of $100 in NextEra Energy stock at the beginning of 2020 would have grown to $133.20 at the end of 2024 while the same investment in the S&P 500 Utilities Index would have yielded $137.70. Our financial performance was strong with 2021 net income growth of 19.3%, 2022 net income growth of 14.8%, 2023 net income growth of 93.5% and 2024 net income was 5.0% lower than 2023. Adjusted EPS growth was 10.4% in 2021, 13.7% in 2022, 9.3% in 2023 and 8.2% in 2024.

Our Company maintains a pay for performance philosophy and the majority of compensation is performance-based as further described in our Compensation Discussion & Analysis.

The higher values for compensation actually paid in 2020, 2021 and 2024 for our PEOs and non-PEO NEOs aligns with strong TSR, net income and adjusted EPS results over the same period. In 2022 and 2023, we continued to deliver outstanding net income and adjusted EPS performance, but the stock price declines in 2022 and 2023 caused our compensation actually paid to decrease notably compared to 2021 and 2020.

Director Compensation

2024 COMPENSATION OF NON-EMPLOYEE DIRECTORS

(A) NAME[(1)(2)]	(B) FEES EARNED OR PAID IN CASH[(3)] ($)	(C) STOCK AWARDS[(4)(5)] ($)	(D) OPTION AWARDS ($)	(E) NON-EQUITY INCENTIVE PLAN COMPENSATION ($)	(F) CHANGE IN PENSION VALUE AND NON-QUALIFIED DEFERRED COMPENSATION EARNINGS ($)	(G) ALL OTHER COMPENSATION[(6)] ($)	(H) TOTAL ($)
Nicole S. Arnaboldi	145,000	185,555	0	0	0	10,000	340,555
Sherry S. Barrat	92,500	185,555	0	0	0	0	278,055
James L. Camaren	145,000	185,555	0	0	0	0	330,555
Kenneth B. Dunn	72,500	185,555	0	0	0	0	258,055
Naren K. Gursahaney	170,000	185,555	0	0	0	0	355,555
Kirk S. Hachigian	165,000	185,555	0	0	0	0	350,555
Maria G. Henry	145,000	185,555	0	0	0	0	330,555
Amy B. Lane	195,000	185,555	0	0	0	0	380,555
Geoffrey S. Martha	72,500	89,716	0	0	0	0	162,216
David L. Porges	165,000	185,555	0	0	0	0	350,555
Dev Stahlkopf	145,000	185,555	0	0	0	0	330,555
John A. Stall	170,000	185,555	0	0	0	0	355,555
Darryl L. Wilson	145,000	185,555	0	0	0	0	330,555

(1) Mr. Martha was appointed to the Board on July 9, 2024.

(2) Mrs. Barrat and Mr. Dunn did not stand for reelection at the 2024 Annual Meeting of Shareholders on May 23, 2024.

(3) Ms. Arnaboldi elected to defer 100% of her annual cash retainer.

(4) Ms. Arnaboldi and Mr. Gursahaney elected to defer 100% of their equity retainer and Ms. Lane elected to defer 40% of her equity retainer.

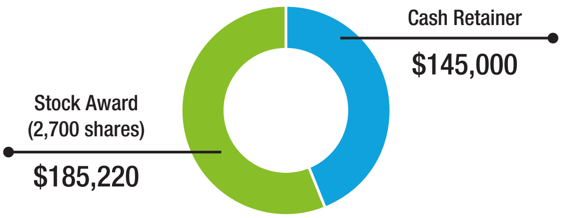
(5) Non-employee directors of NextEra Energy received shares of NextEra Energy common stock in an amount determined by dividing $185,000 by the closing price of the common stock on the date of grant, rounded up to the nearest ten shares. On February 15, 2024, each non-employee director then in office received 3,240 shares of stock valued at $57.27 per share. Mr. Martha received a prorated grant on August 5, 2024 of 1,170 shares valued at $76.68 per share. Dividends are paid on the shares in cash. Dividends on deferred shares are credited to the participant's account under the Deferred Compensation Plan. The amounts in this column represent the aggregate grant date fair value of equity-based compensation awards granted during 2024 to each non-employee director valued in accordance with applicable SEC and accounting rules. For the February 2024 equity compensation award, the grant date fair value was $185,555 per director. The grant date fair value for Mr. Martha's equity compensation award was $89,716.

(6) In accordance with applicable SEC rules, perquisites and personal benefits with an aggregate value of less than $10,000 are omitted. Includes matching contributions to educational institutions on behalf of Ms. Arnaboldi made under the NextEra Energy Foundation's matching gift program, which is available to all employees and directors.

Additional information about director compensation

NextEra Energy directors who are salaried employees of NextEra Energy or any of its subsidiaries do not receive any additional compensation for serving as a director or committee member. Mr. Ketchum is the only such director currently serving on the Board. Director compensation was not increased from 2023 levels. Effective January 1, 2025, non-employee directors of NextEra Energy received an annual cash retainer of $145,000 plus a number of shares of NextEra Energy common stock determined by dividing $185,000 by the closing price of NextEra Energy common stock on the grant date, rounded up to the nearest ten shares. The grant date for the annual retainers paid for 2025 was February 13, 2025, at which time the non-employee directors of NextEra Energy were each granted 2,700 shares of NextEra Energy common stock. These shares are generally not transferable until the director meets the Company's stock ownership guidelines. When joining the Board, newly-elected non-employee directors are awarded a grant of NextEra Energy common stock approximately equal to the annual common stock retainer awarded to existing non-employee directors, prorated based on the new director's date of election to the Board. These shares are not transferable until the director meets the Company's stock ownership guidelines.

ANNUAL NON-EMPLOYEE DIRECTOR COMPENSATION (EFFECTIVE 1/1/2025)



ADDITIONAL CASH RETAINERS ($)	
Lead Director	40,000
Committee Chairs:	
» Audit	25,000
» Nuclear	25,000
» Other committees	20,000

Non-employee Board committee chairpersons receive an additional annual retainer of $25,000 for chairing the Audit Committee or the Nuclear Committee and $20,000 for chairing the other committees. The Lead Director receives an annual retainer of $40,000, and a Lead Director who also serves as a Chair of any Board committee is entitled to receive the committee chair retainer as well as the Lead Director annual retainer. Beginning in 2023, non-employee directors no longer receive a fee for each Board and committee meeting attended. Directors may defer all or a portion of their cash compensation and all or a portion of their equity compensation in the Deferred Compensation Plan and may participate in the Company's matching gift program, which matches gifts to educational institutions up to a maximum of $20,000 per donor per year. Board members may travel on Company aircraft while on Company business and in limited circumstances for non-business reasons if the Company would incur little, if any, incremental cost, space is available and the aircraft is in use for another authorized purpose. Board members may be accompanied by their immediate family members if space is available. Travel expenses to attend Board or committee meetings or while on Board business are reimbursed.

Director stock ownership policy

Pursuant to the Governance Guidelines, to more closely align the interests of directors and shareholders, directors are required to own NextEra Energy common stock in an amount equal to seven times the annual cash retainer within six years after their initial election to the Board. All directors other than Ms. Henry and Ms. Stahlkopf, both of whom joined the Board in 2023, and Mr. Martha, who joined the Board in 2024, currently meet this stock ownership guideline. See Common Stock Ownership of Certain Beneficial Owners and Management for information about director ownership of NextEra Energy common stock as of March 25, 2025.

Questions and Answers About the Annual Meeting

MEETING INFORMATION

TIME AND DATE	PLACE	RECORD DATE
8:00 a.m., Central time May 22, 2025	12 Sixth Street South, Minneapolis, Minnesota 55402	March 25, 2025

Why did I only receive a Notice of Internet Availability of Proxy Materials directing me to the internet instead of the proxy statement and annual report?

Under SEC rules, NextEra Energy is furnishing proxy materials to many of its shareholders on the internet, rather than mailing paper copies of the materials to each shareholder.

On or about April 1, 2025, NextEra Energy mailed to many of its shareholders of record a Notice containing instructions on how to access and review the proxy materials, including the proxy statement and annual report to shareholders, on the internet. The Notice also instructs shareholders how to access their proxy card to be able to submit their proxies on the internet. Brokerage firms and other nominees who hold NextEra Energy shares on behalf of beneficial owners will be sending their own similar notice. Other shareholders, in accordance with their prior requests, have received an e-mail notification of how to access the proxy materials and submit their proxies on the internet. On or about April 1, 2025, NextEra Energy also began mailing a full set of proxy materials to certain shareholders, including shareholders who have previously requested a paper copy of the proxy materials.

If you would prefer to receive printed proxy materials, please follow the instructions included in the Notice. If you have previously elected to receive NextEra Energy's proxy materials electronically, you will continue to receive the materials via e-mail unless you elect otherwise.

How do I access the proxy materials if I received a Notice of Internet Availability of Proxy Materials?

The Notice provides instructions regarding how to view NextEra Energy's proxy materials for the 2025 annual meeting on the internet. As explained in greater detail in the Notice, to view the proxy materials and submit your proxy, you will need to follow the instructions in your Notice and have available your 16-digit control number(s) contained in your Notice.

How do I request paper copies of the proxy materials?

Whether you hold NextEra Energy shares through a brokerage firm, bank or other nominee (in "street name"), or hold NextEra Energy shares directly in your name, as a shareholder of record, through NextEra Energy's transfer agent, Computershare Trust Company, N.A. ("Computershare"), you may request paper copies of the 2025 annual meeting proxy materials by following the instructions listed at www.proxyvote.com, by telephoning 1-800-579-1639 or by sending an e-mail to sendmaterial@proxyvote.com.

What is the purpose of the annual meeting?

At the annual meeting, shareholders will act upon the matters identified in the accompanying notice of annual meeting of shareholders. These matters include:

- the election as directors of the nominees specified in this proxy statement;
- ratification of appointment of Deloitte & Touche as NextEra Energy's independent registered public accounting firm for 2025; and
- approval, by non-binding advisory vote, of NextEra Energy's compensation of its NEOs as disclosed in this proxy statement.

Who may attend the annual meeting?

Subject to space availability, all shareholders as of the record date, or their duly appointed proxies, may attend the annual meeting. Since seating is limited, admission to the meeting will be on a first-come, first-served basis. Registration and seating will begin at 7:30 a.m., Central time. If you plan to attend, please note you will be required to present valid picture identification, such as a driver's license or passport.

Invited representatives of the media and financial community may also attend the annual meeting. You will need proof of ownership of NextEra Energy common stock on the record date to attend the annual meeting:

REGISTERED SHAREHOLDERS	BENEFICIAL OWNERS
If you hold shares directly in your name as a shareholder of record, or if you are a participant in NextEra Energy's Employee Retirements Savings Plan:	**If your shares are held in "street name":**
» If you received the Notice and you plan to attend the annual meeting, you may request an admission ticket by calling NextEra Energy Shareholder Services at: 800-222-4511. » If you received the proxy materials by mail, an admission ticket is attached to your proxy/confidential voting instruction card. If you plan to attend the annual meeting, please submit your proxy but keep the admission ticket and bring it with you to the annual meeting.	» You will need to bring proof you were the beneficial owner of those "street name" shares of NextEra Energy common stock as of the record date, such as a legal proxy or a copy of a bank or brokerage statement and check in at the registration desk at the annual meeting.

For the safety of attendees, all boxes, handbags and briefcases are subject to inspection. Cameras, cell phones, recording devices and other electronic devices are not permitted at the annual meeting.

Will the annual meeting be webcast?

The annual meeting will be webcast (audio, listen only) on May 22, 2025. If you do not attend the annual meeting, you are invited to visit www.nexteraenergy.com at 8:00 a.m., Central time, on Thursday, May 22, 2025 to access the webcast of the annual meeting. You will not be able to vote your shares via the webcast. A replay of the webcast also will be available on NextEra Energy's website for 90 days after the annual meeting.

Who is entitled to vote at the annual meeting?

Only NextEra Energy shareholders at the close of business on March 25, 2025, the record date for the annual meeting, are entitled to receive notice of, and to vote at, the annual meeting. If you were a shareholder on that date, you will be entitled to vote all of the NextEra Energy shares you held on that date at the annual meeting or any adjournment or postponement of the annual meeting.

What are the voting rights of the holders of the Company's common stock?

Each outstanding share of NextEra Energy common stock will be entitled to one vote on each matter properly brought before the annual meeting. As of March 25, 2025, 2,058,580,718 shares of common stock were outstanding.

What constitutes a quorum?

The presence at the annual meeting, in person or by proxy, of the holders of a majority of the shares outstanding as of the record date will constitute a quorum, permitting the business of the meeting to be conducted.

In determining the presence of a quorum at the annual meeting, (a) abstentions in person, (b) proxies received but marked as abstentions as to any or all matters to be voted on that permit abstentions and (c) proxies received with broker non-votes on some but not all matters to be voted on will be counted as present.

What is a broker "non-vote"?

A broker "non-vote" occurs when a broker, bank or other holder of record that holds shares for a beneficial owner ("broker") does not vote on a particular proposal because the broker has not received voting instructions from the beneficial owner and does not have discretionary voting power for that particular proposal. Brokers may vote on ratification of the appointment of NextEra Energy's independent registered public accounting firm even if they have not received voting instructions from the beneficial owners whose shares they hold. However, brokers may not vote on any of the other matters submitted to shareholders at the 2025 annual meeting, including the election of directors or advisory vote on approval of executive compensation, unless they have received voting instructions from the beneficial owner.

What is the difference between holding shares as a shareholder of record and as a beneficial owner?

REGISTERED SHAREHOLDERS

- If your shares are registered directly in your name with NextEra Energy's transfer agent, Computershare, you are considered, with respect to those shares, the "shareholder of record."
- The Notice or, for some shareholders of record, a full set of the proxy materials has been sent directly to you by or on behalf of NextEra Energy.

BENEFICIAL OWNERS

- If your shares are held in "street name," you are considered the "beneficial owner" of the shares.
- The Notice or, for some beneficial owners, a full set of the proxy materials has been forwarded to you by or on behalf of your broker, who is considered, with respect to those shares, the shareholder of record.

How do I submit my proxy or voting instructions?

ON THE INTERNET OR BY TELEPHONE OR, IF YOU RECEIVED THE PROXY MATERIALS BY MAIL, ALSO BY MAIL

ON THE INTERNET	You may submit your proxy or voting instructions on the internet 24 hours a day and up until 11:59 p.m., Eastern time, on Wednesday, May 21, 2025 by going to www.proxyvote.com and following the instructions on your screen. Please have your Notice or proxy/confidential voting instruction card available when you access the web page. If you hold your shares in "street name," your broker, bank, trustee or other nominee may provide additional instructions to you regarding how to submit your proxy or voting instructions on the internet.
BY TELEPHONE	You may submit your proxy or voting instructions by telephone by calling the toll-free telephone number (1-800-690-6903) found on your proxy/confidential voting instruction card or in your internet instructions, 24 hours a day and up until 11:59 p.m., Eastern time, on Wednesday, May 21, 2025 and following the prerecorded instructions. Please have your proxy/confidential voting instruction card or Notice and instructions provided on the internet available when you call. If you hold your shares in "street name," your broker, bank, trustee or other nominee may provide additional instructions to you regarding how to submit your proxy.
BY MAIL	If you received the proxy materials by mail, you may submit your proxy by mail by marking the enclosed proxy/confidential voting instruction card and dating, signing and returning it in the postage-paid envelope provided to: NextEra Energy, Inc. Vote Processing c/o Broadridge 51 Mercedes Way Edgewood, NY 11717 Your proxy/confidential voting instruction card must be received no later than Wednesday, May 21, 2025. If you hold your shares in "street name," your broker, bank, trustee or other nominee may provide additional instructions to you regarding voting your shares by mail.

Please see the Notice, your proxy/confidential voting instruction card or the information your broker provided to you for more information on your options. NextEra Energy's proxy tabulator, Broadridge Investor Communications Solutions, Inc. ("Broadridge"), must receive any proxy/confidential voting instruction card that will not be delivered in person at the annual meeting, or any vote on the internet or by telephone, no later than 11:59 p.m., Eastern time, on Wednesday, May 21, 2025.

If you are a shareholder of record and you return your signed proxy/confidential voting instruction card or submit your proxy on the internet or by telephone, but do not indicate your voting preferences, the persons named as proxies in the proxy/confidential voting instruction card will vote the shares represented by that proxy as recommended by the Board on all proposals.

IN PERSON AT THE ANNUAL MEETING

IN PERSON	All shareholders may vote in person at the annual meeting. However, if you are a beneficial owner of shares, you must obtain a legal proxy from your broker and present it to the inspector of election with your ballot to be able to vote in person at the annual meeting. See the response to “Who may attend the annual meeting?” for additional information on how to attend the annual meeting.

May I change my vote after I submit my proxy or voting instructions on the internet or by telephone or after I return my proxy/confidential voting instruction card or voting instructions?

Yes. If you are a shareholder of record, you may revoke your proxy before it is exercised by:

- providing written notice of the revocation to the Corporate Secretary of the Company at the Company’s offices at:

  P.O. Box 14000
  700 Universe Blvd.
  Juno Beach, Florida 33408-0420

- making timely delivery of later-dated voting instructions on the internet or by telephone or, if you received the proxy materials by mail, also by making timely delivery of a valid, later-dated proxy/confidential voting instruction card; or
- voting by ballot at the annual meeting, although please note that attendance at the meeting will not by itself revoke a previously granted proxy.

You may change your proxy by using any one of these methods regardless of the method you previously used to submit your proxy. If you are a beneficial owner of shares, you may submit new voting instructions by contacting your broker. You may also vote in person at the annual meeting if you obtain a legal proxy as described in the answer to the previous question. All shares for which proxies have been properly submitted and not revoked will be voted at the annual meeting.

How do I vote my Employee Retirement Savings Plan (401(k)) shares?

If you participate in the NextEra Energy, Inc. Employee Retirement Savings Plan (the “plan”), you may give voting instructions to Fidelity Management Trust Company, as trustee of the plan (“Trustee”). If you are a non-bargaining NextEra Energy employee, or a bargaining unit employee outside the state of Florida, you may give your voting instructions to the Trustee by following the instructions you received in an e-mail from NEXTERA ENERGY, INC. id@ProxyVote.com sent to your work e-mail address (unless you opted to receive a paper copy of the proxy materials). If you are a FPL bargaining unit employee in Florida, a participant in the plan who is not a current employee of NextEra Energy or its subsidiaries or if you opted out of e-mail delivery, you may give your voting instructions to the Trustee on the internet or by telephone by following the instructions on your proxy/confidential voting instruction card, or you may give your voting instructions to the Trustee by mail by completing and returning the proxy/confidential voting instruction card accompanying this proxy statement.

Your instructions will tell the Trustee how to vote the number of shares of NextEra Energy common stock in the plan reflecting your proportionate interest in the NextEra Energy Stock Fund and the NextEra Energy Leveraged ESOP Fund. You have this right because the plan deems you to be a “named fiduciary” of the shares of common stock allocated to your account for voting purposes. Your instructions will also determine the vote of a proportionate number of shares of common stock in the NextEra Energy Leveraged ESOP Fund which are not yet allocated to participants. If you do not give the Trustee voting instructions, the number of shares reflecting your proportionate interest in the NextEra Energy Stock Fund and the NextEra Energy Leveraged ESOP Fund will be voted by the Trustee in the same manner as it votes proportionate interests for which it receives voting instructions and your proportionate share of the unallocated NextEra Energy Leveraged ESOP Fund shares will be voted by the Trustee in the same manner as it votes unallocated shares for which instructions are received. The Trustee will vote your shares in accordance with your duly executed instructions received by 11:59 p.m., Eastern time, on Monday, May 19, 2025.

You may also revoke previously given voting instructions by 11:59 p.m., Eastern time, on Monday, May 19, 2025, by filing written notice of revocation with the Trustee or by giving new voting instructions in any of the ways described above. The Trustee will follow the last timely voting instructions which it receives from you. Your voting instructions will be kept confidential by the Trustee.

What is “householding” and how does it affect me?

NextEra Energy has adopted a procedure approved by the SEC called “householding.” Under this procedure, shareholders of record who have the same address and last name and do not participate in electronic delivery of proxy materials will receive only one package containing individual copies of the Notice or proxy materials in paper form for each shareholder of record at the address. This procedure will reduce the volume of duplicate materials shareholders receive, conserve natural resources and reduce NextEra Energy’s postage costs. Shareholders who participate in householding and to whom a full set of proxy materials has been mailed will continue to receive separate proxy cards.

If you are a shareholder of record and are eligible for householding, but you and other shareholders of record with whom you share an address currently receive multiple packages containing copies of the Notice or proxy materials in paper form, or if you hold shares in more than one account, and in either case you wish to receive only a single package for your household in the future, please contact Computershare in writing at:

Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078

or by calling 888-218-4392. You may contact Computershare at the same mailing address or telephone number if you wish to revoke your consent to future householding mailings.

If your household receives only a single package containing a copy of the Notice or the proxy materials, and you wish to receive a separate copy for each shareholder of record, please contact Broadridge toll-free at 866-540-7095, or write to:

Broadridge
Householding Department
51 Mercedes Way
Edgewood, NY 11717

and separate copies will be provided promptly.

Beneficial owners may request information about householding from their banks, brokers or other holders of record.

What vote is required to approve the matters proposed?

A nominee for director will be elected to the Board if the votes cast for such nominee’s election by shareholders present in person or represented by proxy at the meeting and entitled to vote on the matter exceed the votes cast by such shareholders against such nominee’s election. See the Director Resignation Policy described in Proposal 1 for information about NextEra Energy’s policy if a nominee for director fails to receive the required vote. All other voting items will be approved if the votes cast by shareholders present in person or represented by proxy at the meeting and entitled to vote on the matter favoring the action exceed the votes cast by such shareholders opposing the action. Discretionary voting by brokers is only permitted for the ratification of the appointment of Deloitte & Touche as NextEra Energy’s independent registered public accounting firm for 2025. Broker non-votes and abstentions will not affect the outcome or be counted as a vote cast in favor or against any of the other voting items presented.

Unless you give other instructions, the persons named as proxies will vote in accordance with the recommendations of the Board. The Board's recommendations are set forth together with the description of each proposal in this proxy statement.

	PROPOSAL	BOARD VOTE RECOMMENDATION	VOTE REQUIRED	EFFECT OF ABSTENTIONS AND BROKER NON-VOTES
1.	Election of directors	FOR each nominee	Majority of the votes cast	No effect
2.	Ratification of appointment of Deloitte & Touche LLP as NextEra Energy's independent registered public accounting firm for 2025	FOR	Majority of the votes cast	No broker non-votes No effect of abstentions
3.	Approval, by non-binding advisory vote, to approve NextEra Energy's compensation of its named executive officers	FOR	Majority of the votes cast	No effect

Who pays for the solicitation of proxies?

NextEra Energy is soliciting proxies and it will bear the expense of solicitation. Proxies will be solicited principally by mail and by electronic media, although directors, officers and employees of NextEra Energy or its subsidiaries may solicit proxies personally, by telephone or by electronic means, but without compensation other than their regular compensation. NextEra Energy has retained D.F. King & Co., Inc. to assist it in the solicitation of proxies, for which D.F. King & Co., Inc. will be paid a fee of $15,000 plus reimbursement of out-of-pocket expenses. NextEra Energy will reimburse custodians, nominees and other persons for their out-of-pocket expenses in sending the Notice and/or proxy materials to beneficial owners.

Could other matters be decided at the annual meeting?

At the date of printing of this proxy statement, the Board did not know of any matters to be submitted for action at the annual meeting other than those referred to in this proxy statement and does not intend to bring before the meeting any matter other than the proposals described in this proxy statement. If, however, other matters are properly brought before the annual meeting, or any adjourned or postponed meeting, your proxies include discretionary authority on the part of the individuals appointed to vote your shares or act on those matters according to their discretion, including voting to adjourn or postpone the annual meeting one or more times to solicit additional proxies with respect to any proposal or for any other reason.

How can I submit a shareholder proposal for the 2026 annual meeting of shareholders?

Proposals on matters appropriate for shareholder consideration consistent with Rule 14a-8 under the Exchange Act submitted by shareholders for inclusion in the proxy statement and form of proxy for the 2026 annual meeting of shareholders must be received by the Corporate Secretary at the Company's principal executive offices below not later than December 2, 2025. The submission of such proposals by shareholders is subject to regulation by the SEC pursuant to Rule 14a-8.

Under the Bylaws, a shareholder proposal submitted for consideration at the 2026 annual meeting of shareholders, but not for inclusion in NextEra Energy's proxy statement and form of proxy, must be received by the Corporate Secretary no earlier than January 22, 2026 and no later than February 21, 2026. Proposals received before January 22, 2026 or after February 21, 2026 will be considered untimely and not properly presented. Notice of such proposals must contain the information specified in the Bylaws, available at www.investor.nexteraenergy.com/corporate-governance. These advance notice, informational and other provisions are in addition to, and separate from, the requirements that a shareholder must meet in order to have a proposal included in NextEra Energy's proxy statement and form of proxy under SEC regulations.

In addition to satisfying the foregoing advanced notice requirements under the Bylaws, to comply with the universal proxy rules under the Exchange Act, shareholders who intend to solicit proxies in support of director nominees other than the Company's nominees must provide notice that sets forth the information required by Rule 14a-19 under the Exchange Act no later than March 23, 2026.

Shareholder proposals must be sent to the attention of the Corporate Secretary by mail (U.S. certified mail in the case of proposals required to comply with the advance notice provisions of the Bylaws) or by personal delivery to NextEra Energy, Inc. attention: Corporate Secretary, P.O. Box 14000, 700 Universe Boulevard, Juno Beach, Florida 33408-0420.

No Incorporation by Reference

In the Company's filings with the SEC, information is sometimes "incorporated by reference." This means that the Company is referring you to information that has previously been filed with the SEC and the information should be considered as part of the particular filing. As provided under SEC rules, the "Audit Committee Report" and the "Compensation Committee Report" contained in this proxy statement will not be deemed to be "soliciting material" or "filed" with the SEC, except to the extent that the Company specifically requests that the information be treated as soliciting material or the Company specifically incorporates such information by reference into a document filed with the SEC. In addition, this proxy statement includes several website addresses and QR codes. These website addresses and QR codes are intended to provide inactive, textual references only. The information on, or accessible through, these websites is not part of this proxy statement.

This proxy statement also refers to the Company's 2024 Sustainability Report and CDP response. The information within these reports is not incorporated by reference.

Shareholder Account Maintenance

NextEra Energy's transfer agent is Computershare. All communications concerning accounts of NextEra Energy shareholders of record, including address changes, name changes, inquiries as to requirements to transfer shares of common stock and similar issues, can be handled by calling Computershare at 888-218-4392 or by calling NextEra Energy Shareholder Services at 800-222-4511. For other information about NextEra Energy, shareholders can visit NextEra Energy's website at www.nexteraenergy.com.

REGARDLESS OF THE NUMBER OF SHARES YOU OWN, IT IS IMPORTANT THAT YOUR SHARES BE REPRESENTED AT THE ANNUAL MEETING. **Accordingly, the Company requests that you review the proxy materials and submit your proxy or voting instructions on the internet or by telephone at your earliest convenience by following the instructions on your notice of internet availability of proxy materials. Alternatively, if you received your annual meeting proxy materials by mail, you may submit your proxy or voting instructions on the internet, by telephone or by marking, dating, signing and returning the accompanying proxy/confidential voting instruction card.**

By order of the Board of Directors,

DAVID FLECHNER
Vice President, Compliance & Corporate Secretary

Juno Beach, Florida
April 1, 2025

Appendix A: Reconciliations of Non-GAAP to GAAP Financial Measures

The tables below present reconciliations of each non-GAAP financial measure to the most comparable GAAP financial measure for the years ended December 31, 2024 and December 31, 2023. See page 38 of the Company's Annual Report on Form 10-K for the year ended December 31, 2024 for the reasons the Company uses adjusted earnings.

RECONCILIATION OF NET INCOME ATTRIBUTABLE TO NEXTERA ENERGY TO ADJUSTED EARNINGS

	FISCAL YEAR ENDED DECEMBER 31,	
	2024	2023
	($ IN MILLIONS)	
Net Income	$5,698	$ 6,282
Net Loss Attributable to Noncontrolling Interests	1,248	1,028
Net Income Attributable to NextEra Energy	6,946	7,310
Adjustments:		
Net gains associated with non-qualifying hedges	(935)	(1,949)
Change in unrealized losses (gains) on equity securities held in NextEra Energy Resources' nuclear decommissioning funds and OTTI-net	(113)	(165)
Differential membership interests-related	6	65
XPLR investment gains-net	1,129	(1,294)
Gain on disposal of a business	—	(406)
Impairment charge related to investment in Mountain Valley Pipeline	—	58
Less related income tax benefit	30	(234)
Adjusted Earnings	$7,063	$ 6,441

RECONCILIATION OF EARNINGS PER SHARE ATTRIBUTABLE TO NEXTERA ENERGY TO ADJUSTED EARNINGS PER SHARE

	FISCAL YEAR ENDED DECEMBER 31,	
	2024	2023
Earnings Per Share Attributable to NextEra Energy (assuming dilution)	$ 3.37	$ 3.60
Adjustments:		
Net gains associated with non-qualifying hedges	(0.45)	(0.96)
Change in unrealized losses (gains) on equity securities held in NextEra Energy Resources' nuclear decommissioning funds and OTTI-net	(0.05)	(0.8)
Differential membership interests-related	—	0.03
XPLR investment gains-net	0.55	0.64
Gain on disposal of a business	—	(0.20)
Impairment charges related to investment in Mountain Valley Pipeline	—	0.03
Less related income tax expense	0.01	(0.11)
Adjusted Earnings Per Share (assuming dilution)	$ 3.43	$ 3.17

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NextEra Energy, Inc. | 700 Universe Boulevard, Juno Beach, Florida 33408

For more information:

NextEraEnergy.com | **FPL.com** | **NextEraEnergyResources.com**

EXHIBIT 10

ELECTRIC AND MAGNETIC FIELDS MANAGEMENT PLAN

IRONWOOD PROJECT

500 kV TRANSMISSION LINE DETAILED FIELD MANAGEMENT PLAN 3D.NT158175-EMF01

REVISION: C

DATED: 08/27/2025

PRELIMINARY – ISSUED FOR REVIEW

NOT FOR CONSTRUCTION

PROJECT NO. 14341-109

55 East Monroe Street
Chicago, IL 60603-5780 USA
312-269-2000
www.sargentlundy.com

Sargent & Lundy

ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this *Detailed Field Management Plan* has been prepared, reviewed, and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASQC Q9001 Quality Management Systems.

CONTRIBUTORS

Prepared by:

	8/27/25
Joel Archer Project Associate	Date

Reviewed by:

	8/27/25
Freddy Martinez Manager	Date

Approved by:

	8/27/25
Candace Blandford Manager	Date

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DIRECTORY OF TABLES

Table # **Page #**

1 OVERVIEW

1.1 Purpose

The purpose of this document is to describe the measures taken during engineering design of the Ironwood 500 kV Transmission Line ("Project") to reduce electromagnetic field (EMF) strength along the Project right-of-way. Specifically, this report pertains to portions of the Project within the State of California in which the California Public Utilities Commission (CPUC) has provided EMF guidelines and requires that a detailed field management plan (FMP) be developed for projects which require permitting under GO 131-D and are greater than 50 kV.

1.2 Background

There are no specific numerical limitations dictated by the CPUC regarding EMF strength levels within the State of California. The CPUC provides guidelines in Decisions 93-11-013 (1993) & 06-01-042 (2006) that are the basis of this document and the information therein. Some of the notable CPUC guidelines relating to transmission line EMF and the detailed field management plan are summarized below.

- No cost and low-cost magnetic field reduction measures should be considered on new and upgraded projects.
- The low-cost measures should be in the range of 4% of total project cost and achieve a noticeable magnetic field reduction of 15% or greater at the right-of-way edge. These low-cost reduction measures, whether adopted or rejected, should be detailed in the field management plan.
- Low-cost EMF reduction measures are not necessary in agricultural and undeveloped land unless a permanent residence, school or hospital is present on that land.

The CPUC suggests the following methods of reducing magnetic fields. Though not a comprehensive list, these methods should be considered when evaluating potential low-cost measures.

- Increase structure height to increase distance to affected facilities.
- Relocate the transmission line to further increase distance to affected facilities.
- Reduce phase spacing of the transmission line.
- Utilize opposite phasing when two or more transmission circuits are in close proximity.

1.3 Project Description

The Ironwood 500 kV project is approximately 87-miles in length, connecting the existing North Gila Substation (owned by APS) to the existing Imperial Valley Substation (owned by SDG&E) via a 500 kV AC single circuit transmission line. See Figure 1, below, for a project map.

Figure 1 – Project Map

Segment 1 (6.0 miles) traverses from North Gila Substation, within the State of Arizona, to the Arizona/California border and is not described in this document. Segment 2 (52.4 miles) traverses from the Arizona/California border, West, through mostly remote undeveloped land to the start of the agriculturally developed land East of Calexico, CA. The circuit configuration within Segment 2 consists of horizontally phased conductor bundles with two overhead ground wires and a minimum ground clearance requirement of approximately 36.5 ft. Segment 3 (28.7 miles) traverses West through the agriculturally developed land to the Imperial Valley Substation and includes portions in which the Project is adjacent to and parallels the existing Southwest Powerlink 500 kV Transmission Line "SWPL". The circuit configuration within Segment 3 consists of primarily delta phased conductor bundles with two overhead ground wires and a minimum ground clearance requirement of approximately 36.5 ft. Additional design clearance buffers may be utilized for design, exceeding the listed minimum clearances per GO 95. Power flow direction is assumed as from North Gila Substation to Imperial Valley Substation and the contribution of shield wire currents is not included. Exact phasing

(A/B/C) not prescribed in this report since the Project design is still in early engineering. Calculations are based on normal operating conditions, not maximum continuous or emergency operating conditions.

2 EVALUATION OF NO-COST MAGNETIC FIELD REDUCTION MEASURES

2.1 Minimum Electrical Clearance Above Ground

For Segment 2, there are portions that may utilize increased vertical clearance over ground as a no cost byproduct of meeting other engineering requirements, however, since this segment is classified as "undeveloped" and does not pass nearby any sensitive infrastructure, it is exempt from the no cost & low-cost requirements, per the CPUC.

For Segment 3, the majority of the transmission line sections may utilize increased vertical clearance over ground as a no cost byproduct of meeting other engineering requirements. The minimum vertical clearance to ground, as required by General Order 95 within the State of California, is calculated to be 36.5 ft for the Project. The average design vertical clearance to ground for typical sections within this segment is calculated to be approximately 55.0 ft. Figure 3 below illustrates the difference in magnetic field strength along the proposed shared edge of right-of-way and within the proposed Project right-of-way. Utilizing additional vertical clearance to ground decreases the magnetic field strength by approximately 15% along the shared right-of-way edge and much more within the proposed Project right-of-way. Project right-of-way width is assumed to be 250 ft and adjacent SWPL 500 kV right-of-way width is assumed to be 200 ft for the purpose of this report.

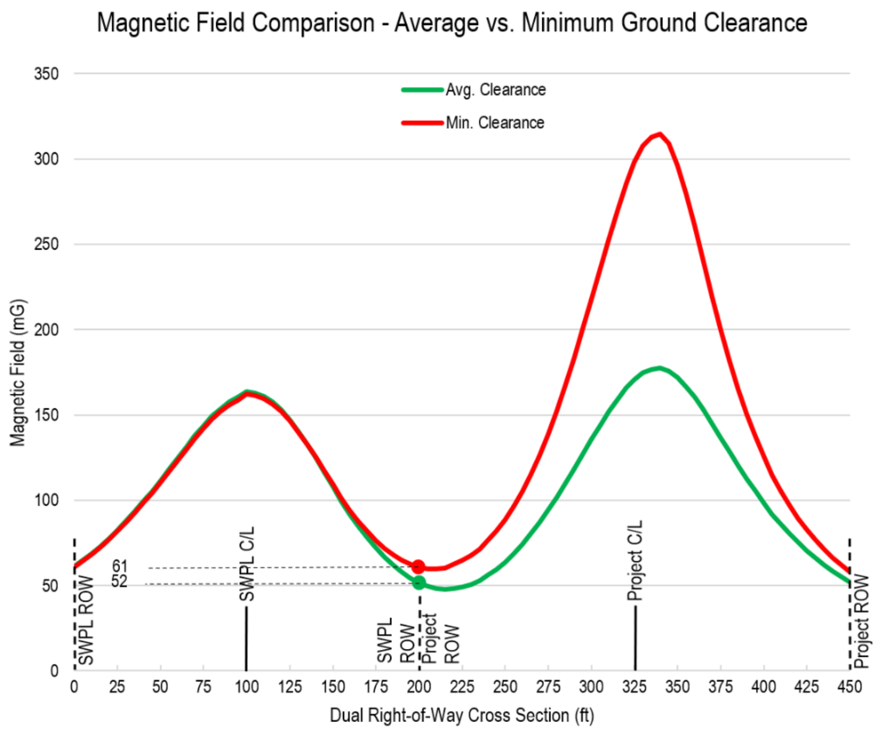

Figure 2 – Vertical Ground Clearance in Segment 3

2.2 Use of Cancelling Phasing

For Segment 2, there are portions that may parallel the existing SWPL 500 kV Transmission Line in an adjacent right-of-way. Within these sections, the Project may utilize cancelling phasing where feasible without adding cost, however, since this segment is classified as “undeveloped” and does not pass nearby any sensitive infrastructure, it is exempt from the no cost & low-cost requirements, per the CPUC.

For Segment 3, within agricultural fields, nearby permanent residences, & parallel to the existing SWPL 500 kV transmission line, the Project will utilize a cancelling phasing configuration that provides a net reduction to the magnitude of the magnetic field strength in these sections. This design implementation is considered a no cost design measure since all that is required is knowledge of the phasing for the existing line and a Project design that utilizes cancelling phasing. Figure 3 below illustrates the difference in magnetic field strength along the proposed shared edge of right-of-way. Utilizing cancelling phasing to that of the existing line, the magnetic field strength can be reduced by approximately 30% along the shared right-of-way edge. Project right-of-way width is assumed to be 250 ft and adjacent SWPL 500 kV right-of-way width is assumed to be 200 ft for the purpose of this report.

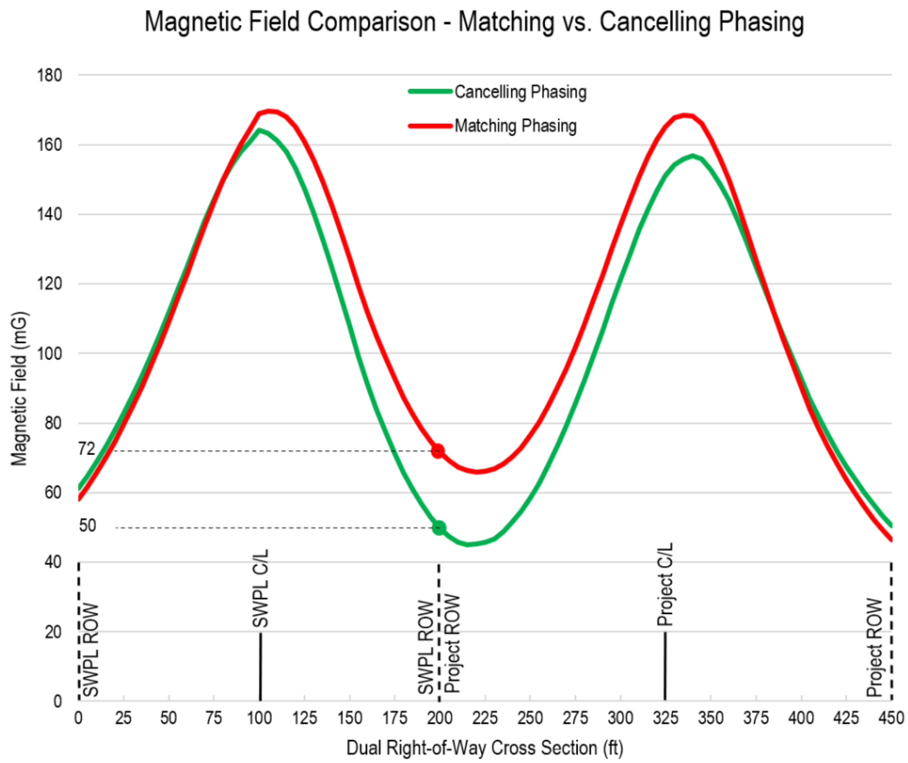

Figure 3 – Cancelling Phasing in Segment 3

2.3 Use of Delta Phase Configuration

For Segment 2, the phase configuration will stay primarily horizontal to accommodate other engineering design requirements. This segment is classified as "undeveloped" and does not pass nearby any sensitive infrastructure such that they are exempt from the no cost & low-cost mitigation requirements, per the CPUC.

For Segment 3, the Project will utilize a delta phase configuration, similar to the existing nearby SWPL 500 kV transmission line that is parallel to the Project right-of-way for a large portion of this segment. Utilizing a delta phase configuration results in a more laterally compact phase footprint and therefore provides a reduction in the lateral footprint of the magnetic field along this segment when compared to a horizontal phase configuration. This is considered a no cost design measure since delta phased monopole structures are already part of the Project design and are the most cost-effective structure type for this portion of the Project. Figure 4 below illustrates the difference in magnetic field strength along the proposed shared edge of right-of-way. By utilizing a delta phase configuration instead of the horizontal phase configuration present in Segments 1 & 2, the magnetic field strength can be reduced by approximately 22% along the shared right-of-way edge. Project right-of-way width is assumed to be 250 ft and adjacent SWPL 500 kV right-of-way width is assumed to be 200 ft for the purpose of this report.

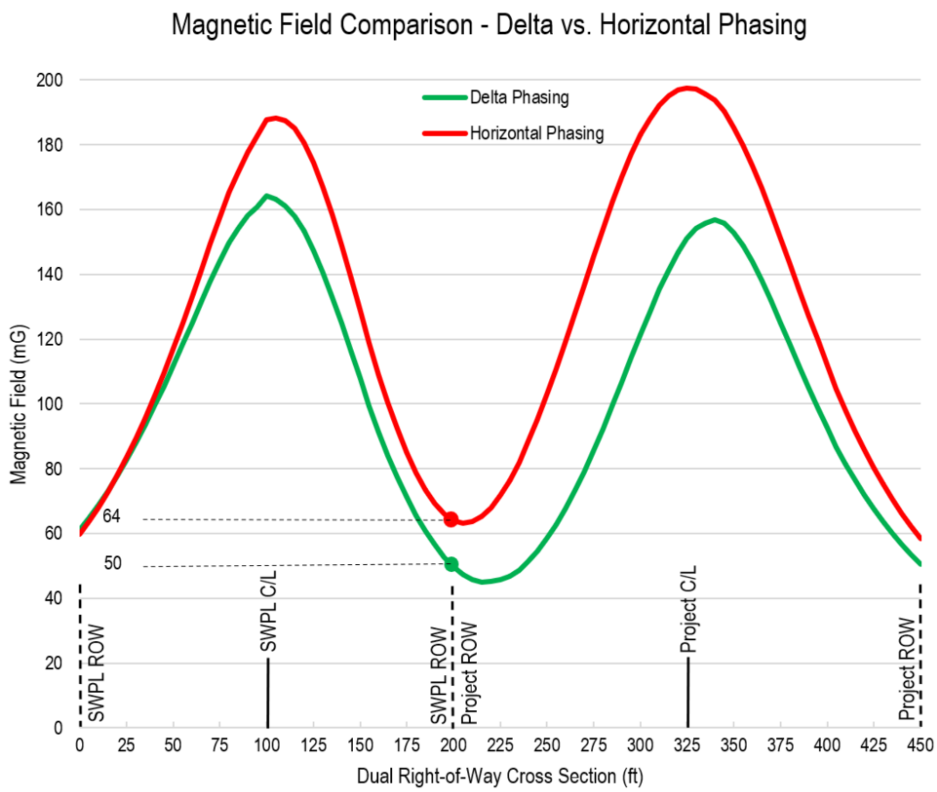

Figure 4 – Delta Phasing in Segment 3

3 EVALUATION OF LOW-COST MAGNETIC FIELD REDUCTION MEASURES

For Segments 1 & 2, the adjacent land use is considered “undeveloped” and do not require “no cost” or “low-cost” measures be taken to reduce electromagnetic fields along the right-of-way. These segments traverse remote areas primarily owned by federal entities with no sensitive infrastructure present along the route.

For Segment 3, multiple “no cost” measures are considered but no “low-cost” measures have been identified.

4 RESULTS AND RECOMMENDATIONS

Per CPUC guidelines, the following land use categories are prioritized in numerical order regarding how mitigation costs will be applied. These numerical categories are referenced in Table 1 under adjacent land use.

1. Schools and licensed day care facilities
2. Residential
3. Commercial/Industrial
4. Recreational
5. Agricultural
6. Undeveloped Land

Project Segment	Location	Adjacent Land Use	Reduction Measure Considered	Measure Adopted? (Yes/No)	Reason(s) if not Adopted	Estimated Cost to Adopt
Segment 1	Arizona (not applicable)	N/A	N/A	N/A	N/A	N/A
Segment 2	Entire Segment	6	N/A	N/A	N/A	N/A
Segment 2	Entire Segment	6	Additional Clearance	Yes	-	No Cost
Segment 3	Majority of Segment	5, 2 [1]	Additional Clearance	Yes	-	No Cost
Segment 3	Majority of Segment (all tangent strs)	5, 2 [1]	Delta Configuration	Yes	-	No Cost
Segment 3	Agricultural Fields & Adjacent to SWPL	5, 2 [1]	Cancelling Phasing	Yes	-	No Cost

[1] Sporadic permanent residence are present along proposed right-of-way within agricultural fields.

Table 1 – EMF Reduction Measures Adopted or Rejected

EXHIBIT 11

LIST OF REQUIRED PERMITS

Exhibit 11
Anticipated Permits and Approvals

Agency	Permit
Federal	
Bureau of Land Management/United States Bureau of Reclamation (co-lead or cooperating agency)	National Environmental Policy Act (NEPA)/Record of Decision (ROD)
United States Army Corps of Engineers	404 Permit
Bureau of Land Management and United States Bureau of Reclamation	ROW Grants/Easements
Bureau of Land Management and United States Bureau of Reclamation	Temporary Use Permits
United States Bureau of Indian Affairs	ROW Grants/Easements
United States Fish and Wildlife Service	Section 7 ESA/Biological Opinion
United States Army Corps of Engineers	Nationwide Permit (NWP) 57 Pre-Construction Notification (PCN)
Local Tribes	Consultation
State/Regional	
California	
California Public Utilities Commission	Certificate of Public Convenience and Necessity (CPCN), including environmental review as required under the California Environmental Quality Act
California Department of Fish and Wildlife	Lake and Streambed Alteration Agreement (LSAA)
Regional Water Quality Control Board	401 Permit
Regional Water Quality Control Board	NPDES (CWA Section 402 Construction Stormwater General Permit)/ SWPPP
California Department of Fish and Wildlife	Incidental Take Permit (ITP) (Section 2081)
California Department of Transportation	Encroachment Permit
Regional Water Quality Control Board	Water Quality Certification
California State Lands Commission	California State Lands Commission Lease
California Public Utilities Commission / Bureau of Land Management	Notice to Proceed
California State Historic Preservation Office	Consultation
Arizona	
Arizona Corporation Commission	Certificate of Environmental Compatibility
Arizona Department of Environmental Quality	Water Quality Certification
Arizona Department of Environmental Quality	Construction General Permit Authorization to Discharge
Arizona State Land Department	Arizona State Land Department Lease
Arizona Department of Fish and Game	ITP
Arizona State Historic Preservation Office	Consultation
Local	
Various (Yuma County, City of Calexico, City of Yuma)	Various Ministerial Permits to the extent not preempted by CPUC G.O. 131-E

Notes: The permits listed in this table are based on preliminary planning and are subject to change.

EXHIBIT 12

GOVERNMENTAL AGENCY CONSULTATIONS

Exhibit 12
Governmental Agency Consultations

Following the project award by the California Independent System Operator ("CAISO") in April 2024, Horizon West Transmission, LLC ("Horizon West") initiated regular pre-filing consultation beginning July 29, 2024. Agency coordination activities included informing those groups likely to be involved in the Proposed Project's evaluation and approval processes of Horizon West's development activities and anticipated timelines, as well as soliciting input regarding specific concerns, areas of interest, or information needs anticipated by these groups. Details regarding Horizon West's pre-filing consultation and engagement are provided in the following sections. The Ironwood Transmission Line Project Routing Study, provided in Appendix K to the Proponent's Environmental Assessment, includes a further summary of public outreach and engagement activities, as well as a discussion of preliminary concerns, alternatives suggested, and significant outcomes of consultation and public engagement.

California Independent System Operator Corporation

In accordance with the requirements and milestones of the Approved Project Sponsor Agreement (APSA), Horizon West has communicated regularly with the CAISO since project award including submitting quarterly construction status reports as scheduled in the APSA.

Potentially Jurisdictional Agencies

Public agencies with potential jurisdiction over portions of the proposed Ironwood Project area include the Bureau of Land Management (BLM), United States Bureau of Reclamation (USBR), United States Army Corps of Engineers, California Public Utilities Commission (CPUC), Arizona Corporation Commission, California Department of Parks and Recreation, Imperial County, and the City of Calexico in California, and Yuma County in Arizona. Public agencies with potential jurisdiction over resources that may occur in the Proposed Project area include the California Department of Fish and Wildlife, United States Fish and Wildlife Service, and Arizona Game and Fish Department. Additional interested public agencies include San Diego County and the Heber Public Utilities District. Horizon West's pre-filing consultation and engagement with these jurisdictional agencies and other agencies is detailed below.

Bureau of Land Management

Horizon West has communicated with and met with BLM approximately monthly since August 2024. Horizon West first reached out to BLM's Desert District Office to discuss permitting strategy and was directed to work with the El Centro Field Office because the El Centro Field Office would take the lead for the National Environmental Policy Act (NEPA) review of the Proposed Project. In initial meetings, Horizon West introduced the Proposed Project, described Horizon West and the CAISO competitive bid process, and shared maps of federal lands that could potentially be crossed by the Proposed Project route. However, despite initial consultation with the El Centro Field Office, recent staffing changes and reallocation of resources may shift the lead office back to the Desert District Office. Horizon West has also introduced the Proposed Project to the Yuma Field Office in Arizona. Horizon West provided an SF-299 and Plan of Development (POD) to all impacted BLM offices. The BLM Desert District is creating a Project Charter to assign staff from various offices to the Proposed Project to create one interdisciplinary team with specialists from several BLM offices. Monthly meetings will continue and will likely increase in frequency as the Project Charter is finalized and permitting moves along.

Imperial County, California

Horizon West has met periodically with Imperial County Supervisors and County Staff from November 2024 through June 2025 to introduce the Proposed Project and to solicit input regarding preliminary concerns and route alternatives for the Proposed Project.

Yuma County, Arizona

Horizon West has communicated with Yuma County Supervisors and Staff during three meetings conducted between November 21, 2024, and April 9, 2025. At these meetings, Horizon West introduced the Proposed Project, discussed routing options, and solicited County feedback.

City of Calexico, California

Between January and March of 2025, Horizon West met with the Planning Director, Mayor Pro Term, and City Manager of the City of Calexico. The project team provided an overview of Horizon West and the Proposed Project. City officials asked about the scale of the Proposed Project and planned capacity and interconnections.

City of Yuma, Arizona

Horizon West met with the Mayor and City Administrators of the City of Yuma on February 21, 2025, and again with City of Yuma Interim City Administrator and Deputy City Administrator on April 10, 2025. Horizon West provided an overview of the Proposed Project and officials provided feedback on routing options, including concerns over routing through Yuma due to zoning constraints. City representatives expressed that the Proposed Project would be important to supporting the City's goals for future growth.

San Diego County, California

On December 19, 2024, Horizon West met with San Diego County Staff to introduce the Proposed Project, the CAISO transmission planning process, and Horizon West's relation to SDG&E. County staff provided feedback and context on local community priorities.

Heber Public Utilities District

On January 30, 2025, Horizon West met with the Heber Public Utilities District. Horizon West shared its commitment to engaging the public well before required input periods to ensure the needs of Imperial Valley are met. Information regarding upcoming open houses was shared to be distributed.

Native American Tribes Affiliated with the Project Area

Horizon West held a total of eight meetings with the Fort Yuma Quechan Tribe between June 15, 2023 and April 8, 2025. Attendees over the course of these meetings included the Fort Yuma Quechan Tribe's President, Vice President, Tribal Council members, Cultural Committee members, and Economic Development Director. In initial meetings, Horizon West introduced the Proposed Project and received tribal input on proposed routing. In later meetings, Horizon West acknowledged the award of the Proposed Project, introduced the project team, discussed potential routing options north and south of the Fort Yuma Quechan Reservation, and heard tribal concerns regarding the negative impact that the development of a transmission line would have on the culturally sensitive areas north of the Reservation. The Ironwood Transmission Line Project Routing Study is provided in Appendix K and includes a summary of meetings with the Fort Yuma Quechan Tribe, a discussion of preliminary concerns, alternatives suggested, and significant outcomes of engagement.

Horizon West also initiated voluntary, informal tribal outreach to area tribes. Horizon West electronically sent project information packets to the following tribes on June 17, 2025: Ak-Chin Indian Community, Barona Group of Capitan Grande Band of Mission Indians, Campo Band of Diegueno Mission Indians, Chemehuevi Indian Tribe, Cocopah Indian Tribe, Colorado River Indian Tribes, Fort McDowell Yavapai Nation, Fort Mojave Indian Tribe, Fort Yuma Quechan Tribe, Ewiiaapaayp Band of Kumeyaay Indians, Gila River Indian Community, Hopi Tribe, Iipay Nation of Santa Ysabel, Inaja-Cosmit Band of Indians, Jamul Indian Village, La Posta Band of Diegueno Mission Indians, Manzanita Band of Kumeyaay Nation, Mesa Grande Band of Diegueno Mission Indians, Mescalero Apache Tribe, Pascua Yaqui Tribe, Pueblo of Zuni, San Pasqual Band of Diegueno Mission Indians, Salt River Pima-Maricopa Indian Community, Sycuan Band of the Kumeyaay Nation, Tohono O'odham Nation, Torres-Martinez Desert Cahuilla Indians, Twenty-Nine Palms Band of Mission Indians, and Viejas Band of Kumeyaay Indians. A project information packet was also mailed to Kwaaymil Laguna Band of Indians on June 24, 2025. As of June 24, 2025, the Hopi Tribe, Colorado River Indian Tribes, Chemehuevi Indian Tribe, and Viejas Band of Kumeyaay Indians have requested to participate in the Project. The Viejas Band of Kumeyaay Indians further stated that the Project site has cultural significance or ties to Viejas and cultural resources have been located within the Proposed Project's vicinity, and requested that a Kumeyaay Cultural Monitor, or a cultural monitor from a Tribe having closer proximity to the Project, be present for ground disturbing activities.

Federal, State, and Local Fire Management Agencies

Horizon West has not yet communicated with federal, state, or local fire management agencies regarding the Proposed Project. The Proposed Project would not be located within any High or Very High Fire Hazard Severity Zones in Federal, State, or Local Responsibility Areas or within locations mapped by the CPUC as Tier 2 or Tier 3 High Fire Threat Districts.

Records of Consultation and Public Outreach

Horizon West is currently executing a detailed stakeholder outreach and engagement process to solicit and collect input from local governmental groups regarding the Proposed Project's design and routing as well as potential impacts and measures to avoid or minimize those impacts. Details regarding Horizon West's pre-filing consultation and engagement are provided in the sections above.

All governmental outreach meetings with CAISO and regular submittals as required by the APSA completed during Horizon West's public outreach process are presented below in Table 1.

Table 1 Public Outreach Meetings

Meeting	Date(s)
Fort Yuma Quechan Tribe	15-Jun-23
Fort Yuma Quechan Tribe	18-Apr-24
Fort Yuma Quechan Tribe	11-Jun-24
Imperial County Supervisors and Staff	13-Nov-24
Imperial County Staff	14-Nov-24
Virtual meeting with Yuma County Staff	21-Nov-24
Fort Yuma Quechan Tribe	22-Nov-24
Yuma County Supervisor and Staff	4-Dec-24
Fort Yuma Quechan Tribe	9-Dec-24
Imperial County Supervisors-elect	19-Dec-24
Imperial County Supervisor	19-Dec-24
San Diego County Staff	19-Dec-24
Fort Yuma Quechan Tribe	23-Dec-24
Heber Public Utilities District	20-Jan-25
City of Calexico Planning Director	29-Jan-25
Mayor and City Administrators of the City of Yuma	21-Feb-25
Fort Yuma Quechan Tribe	21-Feb-25
City of Calexico Mayor Pro Term City Manager	26-Mar-25
City of Calexico Mayor Pro Term and City Manager	26-Mar-25
Chairman of the Imperial County Board of Supervisors	9-Apr-25
Yuma County Board of Supervisors	9-Apr-25
Imperial County Board of Supervisors, District 2	10-Apr-25
Yuma County Board of Supervisors	10-Apr-25
City of Yuma Interim City Administrator and Deputy City Administrator	10-Apr-25
Fort Yuma Quechan Tribe	8-Apr-25
Imperial County Board of Supervisors, District 4	21-May-25
Yuma Irrigation District	16-May-25
Heber Public Schools Superintendent	18-Jun-25
Imperial Valley Regional Chamber of Commerce	19-Jun-25
Imperial County Board of Supervisors, District 3	20-Jun-25

EXHIBIT 13

ANNUAL REVENUE REQUIREMENT

(PUBLIC VERSION)

Exhibit 13 (PUBLIC)
Annual Revenue Requirement

As described in the Confidential Version of its Approved Project Sponsor Agreement, provided in Exhibit 4C, [redacted]:

Year	ATRR
2031	[redacted]
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	

EXHIBIT 14

NOTICE OF APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

**NOTICE OF APPLICATION FOR A
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (A.25-09-[XXX])
AUTHORIZING CONSTRUCTION OF THE IRONWOOD TRANSMISSION LINE PROJECT**

Proposed Project:

Horizon West Transmission, LLC (HWT) has filed an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity (CPCN) requesting authorization to construct the Ironwood Transmission Line Project (Proposed Project). The California Independent System Operator Corporation (CAISO) identified the Proposed Project in its 2022-2023 Transmission Plan as a reliability-driven project needed to add load-serving transmission capacity to meet current and long-term forecast electrical demand and improve system reliability by providing diverse transmission routes for power supply to the region.

Project Description:

The Proposed Project includes the installation of an approximately 86-mile 500-kilovolt (kV) transmission line between the existing North Gila Substation in western Yuma County, Arizona, and the existing Imperial Valley Substation in Imperial County, California. System changes at either the existing North Gila Substation in Arizona (owned by the Arizona Public Service Company (APS)) or the existing Imperial Valley Substation in California (owned by San Diego Gas & Electric Company (SDG&E)) are not included. Construction is expected to begin in 2029, and the transmission line is planned to be operational in December 2030.

Environmental Review:

HWT has prepared a Proponent's Environmental Assessment (PEA) that identifies potential environmental impacts created by the construction and operation of the Proposed Project. The PEA concludes that, with the implementation of Applicant-Proposed Measures, the potential significant environmental impacts associated with the Proposed Project would be reduced to less-than-significant levels, with the exception of Aesthetics and Recreation, where impacts would remain significant and unavoidable.

Pursuant to the California Environmental Quality Act (CEQA), as the lead agency, the CPUC's Energy Division will conduct an independent review of the Proposed Project's environmental impacts. Depending on the results of that review, the Energy Division is expected to prepare an Environmental Impact Report (EIR) identifying and disclosing significant environmental impacts and specifying the mitigation measures or alternatives that would avoid or reduce the environmental impacts.

Public Participation:

The public may participate in the environmental review process by submitting comments on the Notice of Preparation (NOP) of an EIR and draft EIR, and by participating in any scoping meetings or public meetings that may be conducted. For information about the environmental review, contact the CPUC's Energy Division by email at energy@cpuc.ca.gov or call (415) 703-2782.

Members of the public may provide public comments directly on the Docket Card of the Proposed Project via this link: apps.cpuc.ca.gov/c/AXXXXXXX. The CPUC may decide to hold a public participation hearing to take oral public comments.

Assistance in Filing a Protest or Response:

If you wish to file a protest or response you must do so by **DATE**. For questions about how to file a protest or response or about CPUC processes, contact the Public Advisor's Office by email at public.advisor@cpuc.ca.gov, or call 1-866-849-8390 (toll-free) or (415) 703-2074. Use HWT CPCN Application number A.25-09-[XXX] in any communications you have with the CPUC regarding this matter.

For More Information:

To review a copy of HWT's application, or to request further information about the Proposed Project, please contact HWT.

Email: HorizonWest@NEE.com

Call: (833) 734-0723

Website: www.ironwoodtransmission.com

EXHIBIT 15

NEXTERA ENERGY AFFILIATES' SHARED OFFICERS AND RESPONSIBILITIES

Exhibit 15
Shared Corporate Officers

The following officers of Horizon West Transmission, LLC ("Horizon West") are shared with other affiliates.

Name	Horizon West Title	Corporate Role
Matthew Valle	Chairman and Executive Manager	President of NextEra Energy Transmission, LLC ("NEET") – provides executive leadership and oversight to NEET's regulated transmission business
Matthew G. Ulman	Executive Manager	Vice President and Chief Risk Officer of NextEra Energy Resources, LLC ("NEER") – identifying, assessing, and managing the risks that could impact the NEER's operations and financial performance
Mitchell S. Ross	Executive Manager	Vice President and General Counsel of NextEra Energy Resources, LLC – provides legal oversight over NEER's energy business (including NEET transmission).
Jaime Hoffman	President	Executive Director, Development of NextEra Energy Transmission, LLC – oversees NEET's development efforts in the West Region and also serves as President of Trans Bay Cable LLC and GridLiance West LLC
Christopher H. Zajic	Vice President and Treasurer	Vice President, Finance of NextEra Energy Resources, LLC - oversight of financial matters for NEER subsidiaries and serves as Vice President & Treasurer for substantially all of NEER's subsidiaries and NEET's transmission entities
David Flechner	Vice President and Secretary	Vice President, Compliance and Corporate Secretary of NextEra Energy, Inc. ("NEE") – oversight of corporate-wide ethics and compliance for NEE and all of its subsidiaries and serves as Secretary or Assistant Secretary for substantially all of NEE's subsidiaries
Vincent J. Scrima	Vice President	Vice President, Engineering & Construction of NextEra Energy Resources, LLC – oversight of the design, construction and management of all NEE projects

Name	Horizon West Title	Corporate Role
Stephanie Castenada	Assistant Vice President	Executive Director, Finance of NextEra Energy Transmission, LLC – leads the Business Management organization for NEET with responsibility for all financial matters for NEET and its subsidiaries
Jason B. Pear	Assistant Secretary	Managing Attorney, Corporate Governance, NextEra Energy Resources, LLC – responsible for subsidiary corporate governance and serves as Secretary or Assistant Secretary for substantially all of NEE's subsidiaries

EXHIBIT 16

COMPLIANCE WITH COMMISSION'S ENVIRONMENTAL AND SOCIAL JUSTICE ACTION PLAN

Exhibit 16

Compliance with Commission's Environmental and Social Justice Action Plan

Pursuant to General Order (G.O.) 177 Section VI(A)(7)(a), HWT provides the following statement explaining how the Proposed Project is consistent with the goals of the California Public Utilities Commission Environmental and Social Justice Action Plan ("CPUC's ESJ Action Plan").

The Commission's ESJ Action Plan defines Environmental and Social Justice communities ("ESJ communities") as "predominantly communities of color or low-income communities that are underrepresented in the policy setting or decision-making process, subject to a disproportionate impact from one or more environmental hazards, and are likely to experience disparate implementation of environmental regulations and socioeconomic investments in their communities". The ESJ Action Plan also specifies that ESJ communities include the following:

- Disadvantaged Communities, defined as census tracts that score in the top 25% of CalEnviroScreen 3.0, along with those that score within the highest 5% of CalEnviroScreen 3.0's Pollution Burden but do not receive an overall CalEnviroScreen score;
- All Tribal lands;
- Low-income households (Household incomes below 80 percent of the area median; income); and
- Low-income census tracts (Census tracts where aggregated household incomes are less than 80 percent of area or state median income).

According to CalEnviroScreen 4.0 (the most updated version released in 2021), the proposed Ironwood Project crosses through several communities in Imperial Valley, including those near the cities of El Centro and Calexico, that score within the top 25% of the CalEnviroScreen 4.0. Therefore, the Ironwood Project crosses through communities that meet the guidelines for inclusion as an ESJ community under the Commission's ESJ Action Plan.

The ESJ Action Plan includes nine goals and 93 action items reflecting the Commission's priorities. Goal 3, Goal 6, and Goal 9 of the ESJ Action Plan are not directly related to the Ironwood Project as they focus on water, communications and transportation services (Goal 3), enforcement to protect consumers (Goal 6), and involve the monitoring of the CPUC's own environmental and social justice activities (Goal 9). These goals are therefore not discussed further. The Ironwood Project's consistency with Goals 1, 2, 4, 5, 6, 7, and 8 of the ESJ Action Plan is summarized below.

CPUC Goal 1: Consistently Integrate Equity and Access to CPUC Activities and Decision-Making Throughout CPUC Regulatory Activities. Consistent with Goal 1 of the ESJ Action Plan, Horizon West has engaged with area Tribes early on in the development process to inform them of the Proposed Project and seek their input and participation. This outreach effort is detailed in Exhibit 12 and Chapter 5.18 of the PEA. In addition to Tribal outreach, Horizon West initiated public outreach to landowners, including those in ESJ communities within the Imperial Valley identified by the California Office of Environmental Health Hazard Assessment ("OEHHA") by mailing all recorded landowners within the Ironwood Project's initial study area an introductory postcard regarding the project that identified upcoming opportunities for public input. Horizon West hosted six public meetings to provide landowners and other stakeholders the opportunity to discuss the Ironwood Project with Horizon West representatives one-on-one. Additional information about these open houses can be found in Chapter 2 of the PEA.

Through extensive public outreach, HWT has kept the public informed and engaged them in an equitable and meaningful way, consistent with Goal 1 of the CPUC's ESJ Action Plan.

CPUC Goal 2: Increase Investment in Clean Energy Resources to Benefit ESJ Communities, Especially to Improve Air Quality and Public Health. The Ironwood Project will provide additional capacity to the electric grid in the Imperial Valley, which includes several ESJ communities, via the newly constructed 500 kV transmission line. In doing so, the Ironwood

Project will increase energy reliability in ESJ communities and help meet state energy goals, which will improve air quality and public health within the Imperial Valley.

CPUC Goal 4: Increase Climate Resiliency in ESJ Communities. The Ironwood Project will provide additional capacity to the electric grid in the Imperial Valley and will help provide critical reinforcement of the electric grid by providing greater capacity on the transmission grid to power homes and businesses. Specifically, the Ironwood Project will mitigate the resource deliverability constraints identified in the CAISO 2022-2023 Transmission Plan. The Ironwood Project will enhance system reliability by providing redundancy; in the event of a loss of one North Gila-Imperial Valley circuit, power transfers between energy-producing areas and key load centers, such as downtown San Diego, Imperial County, and Orange County, will be maintained. In increasing electrical system reliability, the Ironwood Project will increase climate resiliency in ESJ communities by improving access to reliable electrical power during extreme climate events.

CPUC Goal 5: Enhance Outreach and Public Participation Opportunities for ESJ Communities to Meaningfully Participate in the CPUC's Decision-Making Process and Benefit from CPUC Programs. As discussed under CPUC Goal 1, above, Horizon West has conducted voluntary public outreach for the Ironwood Project early and often as part of developing its PEA, including outreach to Tribes, residents, and the public in areas in which the Ironwood Project is proposed to be constructed. This outreach has provided members of ESJ communities in the Imperial Valley early engagement opportunities to participate in route selection and to provide input during development of the PEA for the Ironwood Project. These early efforts by Horizon West enhance the outreach and public participation opportunities for ESJ communities after the PEA is submitted and the Commission's decision-making process is initiated.

CPUC Goal 7: Promote High Road Career Paths and Economic Opportunity for Residents of ESJ Communities. The Ironwood Project is consistent with CPUC Goal 7 to promote high road career paths and economic opportunity for residents of ESJ communities, specifically with the proposed project aligning with energy related career options. The Ironwood Project will focus on helping to develop the local workforce and transitioning to higher levels of job quality and access by making best efforts to source construction support roles locally. This includes services such as fuel delivery, traffic control, ice/food/water deliver, equipment repair, rental equipment, lodging, concrete delivery, street sweeping, and material delivery. Additionally, construction of the Ironwood Project will enable further development of Imperial County's and Yuma County's energy industries and is likely to spur economic opportunities and benefits for communities within these counties, including the environmental justice communities within Imperial Valley such as Calexico and El Centro.

CPUC Goal 8: Improve Training and Staff Development Related to Environmental and Social Justice Issues Within the CPUC's Jurisdiction. Horizon West has the benefit of services provided by its affiliate's Tribal and Indigenous Relations team that are available to support this project. This team works proactively with Tribes and Indigenous peoples to avoid and resolve issues, support economic and community needs, educate internal personnel and consultants, and support energy development interests. The team regularly hosts internal Tribal relations and cultural sensitivity training for employees. Additionally, support staff and construction teams will complete cultural awareness trainings. Staff working on the Ironwood Project have and will continue to complete such trainings. This training and staff development is consistent with Goal 8 of the CPUC ESJ Action Plan.

EXHIBIT 17

PROPONENT'S ENVIRONMENTAL ASSESSMENT

(FILED VIA ARCHIVAL GRADE DVD)