Round Mountain 500 kV Area Dynamic Reactive Support Project Project Sponsor Selection Report

February 28, 2020

California Independent System Operator Corporation

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1. INTRODUCTION

This report describes the competitive solicitation process conducted by the California Independent System Operator Corporation (ISO) for the Round Mountain 500 kV area dynamic reactive support project, for which the ISO has solicited proposals for 500 MVAr of dynamic reactive support devices to be installed in either of two alternative configurations connected either (1) to the 500 kV transmission lines between Round Mountain Substation and Table Mountain Substation owned by Pacific Gas and Electric Company (PG&E) or (2) separately to Round Mountain Substation at 230 kV and to Table Mountain Substation at 230 kV. The ISO conducted this competitive solicitation because, in its 2018-2019 transmission planning process, the ISO identified a reliability-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 Round Mountain 500 kV area dynamic reactive support project. The twelve different qualified proposals that the ISO reviewed from the six project sponsors for the Round Mountain 500 kV area dynamic reactive support 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 Round Mountain 500 kV area dynamic reactive support 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 LS Power Grid California, LLC (LSPGC), a wholly-owned subsidiary of LS Power Associates, L.P., as the approved project sponsor to finance, construct, own, operate, and maintain the Round Mountain 500 kV area dynamic reactive support project.

2 BACKGROUND

2.1 The Round Mountain 500 kV Area Dynamic Reactive Support 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 2018-2019 transmission plan identified a reliability-driven need for 500 MVAr of dynamic reactive support devices to be installed in the vicinity of PG&E's Round Mountain Substation. The ISO governing board approved the Round Mountain 500 kV area dynamic reactive support project on March 27, 2019.

Following approval of the transmission plan, the ISO opened a bid solicitation window on April 22, 2019, which provided project sponsors the opportunity to submit proposals to finance, construct, own, operate, and maintain the Round Mountain 500 kV area dynamic reactive support project. 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 2018-2019 Transmission Planning Process Phase 3 Sequence Schedule, the bid solicitation window remained open through August 23, 2019.

After the ISO opened the bid solicitation window, on May 10, 2019 the ISO posted a paper on its website entitled *Round Mountain 500 kV Area Dynamic Reactive Support Description and Functional Specifications for Competitive Solicitation – Revision 1* (ISO Functional Specifications) updating the description of the Round Mountain 500 kV area dynamic reactive support project to provide for the two alternative configurations.[1] As described in the ISO Functional Specifications for the project, the new dynamic reactive support devices are justified on reliability grounds, *i.e*., on the basis that the ISO has determined that they are necessary to ensure reliability in a major portion of the ISO controlled grid. The Round Mountain 500 kV area dynamic reactive support project includes 500 MVAr of dynamic reactive support devices in the vicinity of Round Mountain Substation. The ISO Functional Specifications indicate that the ISO solicited bids for either of two alternatives for the dynamic reactive support in the vicinity of the Round Mountain 500 kV substation and that the evaluation of the bids submitted for either of the alternatives would include evaluation of the cost of the non-competitively bid facilities identified to be constructed by PG&E to interconnect the specific dynamic reactive support facilities proposed by the project sponsor. The ISO Functional Specifications indicate that the dynamic reactive support may be provided by any of the following types of devices: Static VAR Compensator (SVC) with thyristor switched capacitors, Static Synchronous Compensator (STATCOM), synchronous condensor, or inverter associated with a battery storage project, as long as voltage support requirements would take precedence over any other operation of the battery storage facility. The ISO Functional Specifications also indicate that the project must be designed for high availability.

1 http://www.caiso.com/Documents/RoundMountain500kVAreaDynamicReactiveSupportDescriptionandFunctionalSpecs-Revision1.pdf

The ISO Functional Specifications indicate that alternative 1 would include a new 500 kV breaker and a half switching station with three bays and six positions to be looped into the 500 kV transmission lines at a point between Round Mountain Substation and approximately halfway between Round Mountain and Table Mountain Substations to interconnect the dynamic reactive support. For alternative 1, the dynamic reactive support device must be installed in two blocks completely independent of each other and have their own dedicated connections to the bus in order to accommodate maintenance and contingencies of the dynamic reactive support device. The ISO Functional Specifications also specify that there can be no single point of failure between the two blocks, the blocks cannot share a 500 kV breaker, and the associated step-up transformers must be separated by a blast wall. The ISO Functional Specifications (1) indicate that PG&E will be responsible to build the loop-in tie lines connecting the new switching station to the existing Round Mountain to Table Mountain 500 kV lines and (2) specify that if the tie lines are less than one mile in length they may be on double circuit towers, but if the tie lines are one mile or longer, the circuits must be on single circuit towers.

The ISO Functional Specifications indicate that alternative 2 would include one +250/-250 MVAr block of the dynamic reactive support connected at 230 kV to Round Mountain Substation and another +250/-250 MVAr block of the dynamic reactive support connected at 230 kV to Table Mountain Substation. For alternative 2, PG&E would install second 500/230 kV transformers in both Round Mountain and Table Mountain Substations and would extend the 230 kV bus to facilitate the interconnection of the dynamic reactive support device.

In the ISO Functional Specifications, the ISO provided estimates of the costs for the portion of the project not subject to competitive solicitation that would be incurred by PG&E to interconnect the proposed Round Mountain 500 kV area dynamic reactive support project in either of the two alternative configurations, but the ISO did not provide an estimate of the costs of the project for which it is conducting this competitive solicitation. As stated in the ISO Functional Specifications, for alternative 1, the cost estimates for PG&E's scope of work depend on the distance of the new switching station from the existing 500 kV lines. The cost estimates provided in the ISO Functional Specifications for a double circuit 500 kV line and a single circuit 500 kV line were $4 million per mile and $2.5 million per mile, respectively. For alternative 2, the cost estimates for PG&E's scope of work were $91 million and $43 million, for PG&E's work at Round Mountain Substation and Table Mountain Substation, respectively. The ISO Functional Specifications specify that the latest in-service date for the Round Mountain 500 kV area dynamic reactive support project is June 1, 2024. Upon completion of the project, the approved project sponsor must turn the facility or facilities over to ISO operational control.

The ISO identified and posted key selection factors for the Round Mountain 500 kV area dynamic reactive support project.[2] These are the tariff criteria the ISO determined are the most important for selecting a project sponsor for this reliability-driven project. For purposes of this project, the ISO identified the following subsections of ISO Tariff Sections 24.5.4 as the key selection factors:

[2] http://www.caiso.com/Documents/KeySelectionFactors-2018-2019TransmissionPlanningProcess.pdf

- 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(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."

- 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 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 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."

The ISO described these key selection factors during a stakeholder information conference call on April 11, 2019.[3]

The ISO evaluated fourteen applications from six project sponsors – (1) Horizon West Transmission, LLC (HWT), an affiliate of NextEra Energy, Inc., which submitted eight proposals, (2) LS Power Grid California, LLC (LSPGC), a wholly-owned subsidiary of LS Power Associates, L.P., (3) SP Transmission 1, LLC (SPT1), a wholly-owned subsidiary of Southern Power Company, (4) Starwood Energy Group Global Inc. (SEGG), which submitted two proposals and proposes to form a special purpose entity to own and operate the project, (5) Tenaska, Inc. (Tenaska), which proposes to form a special purpose entity to own and operate the project, and (6) TransCanyon Round Mountain, LLC, an affiliate of Berkshire Hathaway Energy Company and Pinnacle West Capital Corporation (TransCanyon). The ISO posted a final list of validated project sponsor applications on October 14, 2019.[4] The ISO found that twelve of the fourteen proposals of the six project sponsors 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 December 4, 2019.[5] The ISO found that all six project sponsors and their twelve 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

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[3] http://www.caiso.com/Documents/2018%E2%80%932019TransmissionPlanningProcessPhase3CompetitiveSolicitation.pdf

[4] http://www.caiso.com/Documents/ListofValidatedProjectSponsorApplications-RoundMountain500kVDynamicReactivePowerSupport.pdf

[5] http://www.caiso.com/Documents/LIstofQualifiedProjectSponsorsandProposals-RoundMountain500kVDynamicReactivePowerSupport.pdf

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 2018-2019 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:

- Project Sponsor, Name and Qualifications
- Past Projects, Project Management and Cost Containment
- Financial
- Environment and Public Process
- Substation
- Transmission Line
- Construction
- Operation and Maintenance
- Miscellaneous
- Officer Certification
- 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 October 14, 2019, as described in Section 2.1 of this report. As also described in Section 2.1, the ISO validated twelve of the fourteen applications. The ISO determined that two applications did not provide

[6] http://www.caiso.com/Documents/2018-2019CompetitiveSolicitationQuestionsMatrix.pdf

sufficient information to allow the ISO to determine how the proposals could meet the ISO Technical Specifications for the project.

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 six project sponsors and their twelve 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 Round Mountain 500 kV area dynamic reactive support 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 December 4, 2019. 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 with regard to 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 Round Mountain 500 kV area dynamic reactive support 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 with regard to 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. 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 Round Mountain 500 kV Area Dynamic Reactive Support Project

The ISO evaluated twelve validated and qualified project sponsor applications for the Round Mountain 500 kV area dynamic reactive support project submitted by six project sponsors:

- Horizon West Transmission, LLC (HWT), an affiliate of NextEra Energy, Inc., which submitted eight proposals, of which the ISO validated six
- LS Power Grid California, LLC (LSPGC), a wholly-owned subsidiary of LS Power Associates, L.P.
- SP Transmission 1, LLC (SPT1), a wholly-owned subsidiary of Southern Power Company
- Starwood Energy Group Global Inc. (SEGG), which submitted two proposals and proposes to form a special purpose entity to own and operate the project
- Tenaska, Inc. (Tenaska), which proposes to form a special purpose entity to own and operate the project
- TransCanyon Round Mountain, LLC, an affiliate of Berkshire Hathaway Energy Company and Pinnacle West Capital Corporation (TransCanyon)

All six entities are qualified and submitted strong, competitive applications supporting their proposals. As a result, the ISO had to make detailed distinctions among the six project sponsors and their twelve validated and qualified proposals in the comparative analysis process in selecting the approved project sponsor.

Horizon West Transmission, LLC (HWT)

According to its six validated and qualified proposals, HWT 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). HWT indicated that HWT 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; Section 3)

HWT indicated that NextEra, HWT's ultimate parent, and its wholly owned subsidiary NEET are headquartered in Juno Beach, Florida and that NextEra's principal subsidiaries are Florida Power & Light Company (FPL) and NextEra Energy Resources, LLC (NEER). HWT 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 FPL and its subsidiaries, including NEET and HWT. (Section 3)

HWT 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 Texas, operated by its affiliate Lone Star Transmission, LLC (Lone Star), and New Hampshire, a project in construction and another in development in California, projects in pre-construction development in New York, Texas and Ontario, Canada, as well as numerous other projects in earlier stages of development throughout the United States. (Executive Summary; Section 3)

HWT Access to Affiliate Financial Support

HWT indicated that HWT's indirect parent NEECH would finance the project for HWT from operating cash flow, cash on hand, or currently available credit and that NEECH is a wholly-owned subsidiary of NextEra. (Executive Summary; Section 3) HWT provided a copy of a corporate guarantee agreement whereby NextEra provides a blanket guarantee of certain obligations of NEECH. (F-2)

LS Power Grid California, LLC (LSPGC)

According to its proposal, LSPGC is a Delaware limited liability company established to own transmission projects in California, including the instant project. LSPGC stated that, through intermediate holding companies (LSP Transmission Holdings II, 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 stated that a similar ownership and organization structure has been used by LS Power for its past projects, including all of its transmission projects. (Section 3)

LSPGC indicated that it would utilize LS Power personnel to perform or manage all aspects of the project. LSPGC also identified three affiliates as particularly relevant to its proposal: (i) Cross Texas Transmission, LLC (Cross Texas Transmission), a transmission service provider in Texas; (ii) DesertLink, LLC (DesertLink), the owner of the Harry Allen-Eldorado 500 kV transmission line currently under construction; and (iii) Great Basin Transmission South, LLC (Great Basin Transmission-South), owner of a 75% interest in the One Nevada Transmission Line (ON Line) facilities in Nevada. (Section 3)

LSPGC Access to Affiliate Financial Support

LSPGC indicated that LS Power would fund all project activities. (Executive Summary) LSPGC provided a letter from LS Power, signed by an officer of LS Power's general partner, indicating LS Power's financial support for the project. (F-2)

Starwood Energy Group Global Inc. (SEGG)

According to its two proposals, SEGG is an affiliate of private real estate investment firm Starwood Capital Group Global L.P. and 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. (Section 3)

SEGG indicated that it would establish and manage a special purpose entity to finance, construct, own, maintain, and operate the project if it is selected as the approved project sponsor. SEGG indicated that it would manage the special purpose entity through one general opportunity fund, Starwood Energy Infrastructure Fund III U.S. AIV, L.P. (SEIF III) and affiliated investment vehicles. (Section 3)

SEGG indicated that the project would be funded by Starwood Energy, a private investment firm based in Greenwich, CT that specializes in deploying equity capital in energy infrastructure investments, and that Starwood Energy has sufficient uncommitted capital through SEIF III to support the development, construction, maintenance, and operation of the project. SEGG indicated that SEIF III would own the project company through an indirect affiliate. (QS-2)

SEGG Access to Affiliate Financial Support

SEGG indicated that once the project is placed into service, SEIF III would provide a guarantee to support the project's operational needs, as required. (Section 3) SEGG also provided a corporate parent guarantee letter from Starwood Energy for the financial backing of the project. (Section 3; QS-2)

SP Transmission 1, LLC (SPT1)

According to its proposal, SPT1 is a Delaware limited liability company formed in 2019 for the purpose of owning a portfolio of transmission assets in the ISO market, including the assets described in its proposal. SPT1 indicated that it is a wholly-owned subsidiary of Southern Power Company (SPC) and that SPC would provide funding and credit support for SPT1 and would provide or be responsible for services related to the siting, permitting, design, engineering, procurement, and construction of the project. SPT1 indicated that another affiliate of SPT1, Southern Company Services, Inc. (SCS), would provide additional engineering and construction support for SPT1 and would be responsible for post-construction monitoring of project operations, maintenance and taking actions at the direction of the ISO. (Section 3)

SPT1 indicated that SPC and SCS are wholly owned subsidiaries of Southern Company, which is headquartered in Atlanta, Georgia and is the parent company of Georgia Power, Alabama Power, Mississippi Power, and SPC. SPT1 indicated that these companies own, operate, and maintain extensive generation and transmission facilities across the U.S. SPT1 indicated that SCS provides services on behalf of these affiliated companies, including transmission-related operations and maintenance activities and operation of the Southern Company systems, and that the experience of these employees would be utilized to complete the project. (Section 3)

SPT1 Access to Affiliate Financial Support

SPT1 provided a financial assurance letter from SPC indicating that it would backstop the project’s future financial obligations through a parent guaranty. (QS-2, F-2)

Tenaska, Inc. (Tenaska)

According to its proposal, Tenaska would establish a special purpose Delaware limited liability company jointly formed and controlled by Tenaska Energy, Inc. (Tenaska Energy) and Tenaska Energy Holdings, LLC (Tenaska Holdings), and it would own all of the assets associated with the project during the development, construction period, and operating period of the project. Tenaska indicated that Tenaska Energy is a privately held Delaware corporation and one of the largest private, independent energy developers and owners of power production and other energy facilities in the United States and that Tenaska Holdings is a privately held Delaware limited liability company. Tenaska indicated that the equity interests in Tenaska Energy and Tenaska Holdings are owned by private individuals and entities formed for the benefit of their family members, and each of these individuals is a current or former officer, employee, or consultant of Tenaska Energy. (Section 1)

Tenaska Access to Affiliate Financial Support

Tenaska indicated that the special purpose entity that would be created for this project would be funded by a combination of sponsor equity and project debt provided by capital markets, and the parent affiliates of Tenaska would likely contribute 100 percent of equity capital and be indirect owners of the special purpose entity. (F-2, F-5)

TransCanyon Round Mountain, LLC, an affiliate of Berkshire Hathaway Energy Company and Pinnacle West Capital Corporation (TransCanyon)

According to its proposal, TransCanyon is a single member limited liability company owned by TransCanyon, LLC (together with its other affiliates collectively referred to as TransCanyon). TransCanyon indicated that TransCanyon, LLC is a joint venture limited liability company formed for the purpose of developing, acquiring, siting, permitting, designing, financing, constructing, owning, operating, and maintaining independent transmission assets in the Western Interconnection. TransCanyon indicated that the membership interests of TransCanyon, LLC are equally held by BHE U.S. Transmission, LLC (BHT) and Bright Canyon Energy Corporation (BCE), each through a wholly owned direct subsidiary. (Section 3)

TransCanyon indicated that the following Berkshire Hathaway Energy Company (BHE) subsidiaries in particular have significant experience in developing, constructing and operating electric transmission facilities and/or other related energy infrastructure, and provide this experience for the benefit of the TransCanyon team and ultimately the project:

- BHT, the subsidiary engaged in the acquisition, ownership, and development of electric transmission facilities
- PacifiCorp, a vertically-integrated electric utility operating in California, Idaho, Oregon, Utah, Wyoming, and Washington
- BHE Canada, a subsidiary focused on business opportunities within all aspects of the energy infrastructure market across Canada
- AltaLink, Alberta's largest regulated electric transmission company
- MidAmerican Energy Company, a vertically-integrated electric and gas utility operating in Iowa and several surrounding states
- BHE Renewables, a subsidiary that oversees unregulated solar, wind, hydro and geothermal projects that produce energy for both the wholesale market and for customers under long-term power purchase agreements, including in California

(Section 3)

TransCanyon also indicated that Pinnacle West Capital Corporation (PNW) is an energy holding company headquartered in Phoenix and incorporated in the State of Arizona, whose principal subsidiaries are Arizona Public Service (APS) and BCE. (Section 3)

TransCanyon Access to Affiliate Financial Support

TransCanyon indicated that it would be firmly backed by a performance guaranty from its two parent companies, PNW and BHE. (QS-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 of the subsequent more narrow selection factors. The ISO will therefore 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 with regard to each of the encompassed selection factors, or (2) the ISO's comparative analysis of the project sponsors 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

(Section 3 - General Project Information, QS-1, QS-4, E-1, E-10, E-11, E-13, S-1, S-5, T-5)

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. A proposal that best satisfies this criterion will contribute significantly to ensuring that the project sponsor selected will develop the project in an efficient, cost-effective, and timely manner, which is particularly important for this project, because the timing of this project is critical to ensure reliability in a major portion of the

ISO controlled grid, as the ISO's 2018-2019 transmission plan points out that adding voltage support in the area will mitigate high voltages after the Diablo Canyon Power Plant retires in 2025.

3.4.1 Information Provided by HWT for Proposals 1, 2, and 3

HWT indicated that it has acquired an option to purchase the parcel on which the project would be located north of State Highway 36 and contiguous to and west of PG&E's Round Mountain-Table Mountain 500 kV transmission lines in Tehama County. HWT provided a copy of the option agreement. (E-1, E-10, E-13)

3.4.2 Information Provided by HWT for Proposal 6

HWT indicated that it has acquired an option to purchase the parcel on which the project would be located east of and contiguous to PG&E's Round Mountain Substation in Shasta County. HWT provided a copy of the option agreement. (E-1, E-10, E-13)

3.4.3 Information Provided by HWT for Proposal 7

HWT indicated that it has acquired options to purchase its preferred parcels on which the project would be located, including: (1) a parcel east of and contiguous to PG&E's Round Mountain Substation in Shasta County; and (2) a parcel west of PG&E's Table Mountain Substation and south of Cottonwood Road in Butte County. HWT provided a copy of the option agreements. (E-1, E-10, E-13)

3.4.4 Information Provided by HWT for Proposal 8

HWT indicated that it proposes to "co-locate" the project on existing PG&E property. HWT indicated that it would enter into negotiations with PG&E to secure the right to use the existing land in Round Mountain and Table Mountain Substations if the ISO selects it as the approved project sponsor for this proposal. (QS-3, E-1, E-10) HWT indicated that this proposed approach is consistent with comments made by California Public Utilities Commission (CPUC) commissioners in approving HWT's Suncrest SVC project and that the CPUC's authority to direct public utilities to make their existing rights-of-way available for public use would appear to derive from California Public Utilities Code § 762, which authorizes the CPUC to require coordination between public utilities and that they share costs. (QS-3) HWT indicated that if the proposal to purchase the PG&E property is unsuccessful, HWT also has acquired options to purchase land contiguous to Round Mountain Substation and less than a half-mile from Table Mountain Substation, which it indicated would provide sufficient area at each location to construct the project, if necessary. (QS-3, E-10, E-13)

3.4.5 Information Provided by LSPGC

LSPGC indicated that it has acquired options to purchase its preferred parcel and an alternative parcel for the project and that its preferred parcel is located contiguous to the right-of-way for PG&E's Round Mountain-Table Mountain 500 kV transmission lines. LSPGC indicated that the location of its preferred and alternative parcels is between Round Mountain Substation and Table Mountain Substation. LSPGC provided a copy of its option agreements. (E-1, E-10, E-13)

LSPGC also indicated that its proposed site avoids the shallow volcanic rock formations prevalent along the existing Round Mountain-Table Mountain 500 kV transmission line corridor. LSPGC indicated that it has completed site-specific geotechnical borings and determined that the site will minimize work and costs associated with site grading and subsurface construction. (Executive Summary, E-10, S-5)

3.4.6 Information Provided by SEGG for Proposals 1 and 2

SEGG indicated that it has acquired an option to purchase the land required for the project, which is located in Tehama County east of PG&E's Round Mountain-Table Mountain 500 kV transmission lines, south of State Route 36, and west of the village of Paynes Creek. (E-1, E-10, E-13)

3.4.7 Information Provided by SPT1

SPT1 indicated that it has acquired options to purchase several parcels for its primary site, which are located west of PG&E's Round Mountain-Table Mountain 500 kV transmission lines and north of State Highway 36, west of the village of Paynes Creek. SPT1 indicated that it has acquired options to purchase alternative project sites located west of PG&E's Round Mountain-Table Mountain 500 kV transmission lines and south of State Highway 36 and west of the transmission line and south of Lanes Valley Road approximately three miles north of Highway 36. (E-1, E-10, S-5)

3.4.8 Information Provided by Tenaska

Tenaska indicated that it has acquired an option to purchase the land required for the project, which is located in Tehama County west of PG&E's Round Mountain-Table Mountain 500 kV transmission lines, north of State Route 36, and west of the village of Paynes Creek. (E-1, E-10, E-13)

3.4.9 Information Provided by TransCanyon

TransCanyon indicated that it has executed a purchase option agreement to purchase the parcel on which it proposes to construct the project, which is located approximately 0.25 miles to the east of the PG&E Round Mountain–Table Mountain 500 kV transmission lines. TransCanyon provided a copy of the executed option agreement and a typical easement agreement. (E-1))

3.4.10 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 and other land rights they possess and are proposing to contribute to this project.

HWT, for its proposals 1, 2, 3, 6, and 7, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon indicated that they have acquired an option to purchase the parcels on which they propose to construct the project.

HWT, for its proposal 8, proposes to "co-locate" the project on existing PG&E property. However, HWT does not currently have the land rights necessary to build the project on the PG&E sites and indicated it has not discussed this proposed co-location with PG&E.

This creates uncertainty and potential risk. HWT noted that it has acquired options to purchase alternative sites, but its proposal 8 did not provide specific project details for a project that would be located at the alternate sites.

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 there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, and 7, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon and that those proposals are better than HWT's proposal 8 with regard to this factor because they have acquired an option to purchase the land that they would need for the project and because HWT, for its proposal 8, has less certainty regarding obtaining the land rights necessary to build the project on its primary site or obtaining agreement with PG&E to use its land. The CPUC's authority referenced by HWT to direct a public utility to make its property available for public use would apply to all project sponsors, assuming the CPUC would use it. The ISO notes that regarding the Suncrest SVC project, the CPUC ultimately approved a solution that was outside of existing public utility property and that the ISO determined had the lowest cost cap and more robust binding cost containment measures.

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."

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

(Section 3 - General Project Information, QS-1, QS-4, P-1, P-3, E-1, E-2, E-3, E-4, E-7, E-8, E-9c, E-10, E-11, E-12, E-14a, E-14b, E-15a, E-15b, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-5, T-1)

3.5.1 Information Provided by HWT for Proposals 1, 2, 3, 6, 7, and 8

HWT provided a list of 22 transmission line projects, including 18 in California, for which it and its team have acquired land rights for transmission lines. HWT provided a list of 19 substation projects, including 15 in California, for which its team acquired land rights for substations. (E-14a, E-14b, E-15a, E-15b)

3.5.2 Information Provided by LSPGC

LSPGC provided a list of 29 transmission projects, including 15 in California, for which it and its team have acquired land rights for transmission line projects. LSPGC provided a list of 28 substation projects, including 14 in California, for which it and its team have acquired land rights for substation projects. (E-14, E-15)

3.5.3 Information Provided by SEGG for Proposals 1 and 2

SEGG provided a list of eight transmission line projects; however, none of the projects required SEGG or the members of its team to acquire rights-of-way. SEGG provided a list of eight substation projects, but none of the projects required SEGG or the members of its team to acquire land or rights-of-way. (E-14, E-15)

3.5.4 Information Provided by SPT1

SPT1 indicated that it and its team have acquired land rights for six transmission line projects, one of which was located in in California. SPT1 noted that it and its team have also completed 17 substation and generation projects, one of which was located in California. (P-1, E-14, E-15)

3.5.5 Information Provided by Tenaska

Tenaska indicated that it and its team have acquired land rights for six transmission line projects, three of which were in California. Tenaska also indicated that it and its team have acquired land rights for four substation projects, two of which were in California. (E-14, E-15)

3.5.6 Information Provided by TransCanyon

TransCanyon indicated that it and its team have acquired land rights for six transmission line projects and that four of them were in California. TransCanyon also indicated that it and its team have acquired land rights for five substation projects and that three were in California. (E-14, E-15)

Incremental Costs Associated with Use of Existing Rights-of-Way

(Section 3 - General Project Information, E-1, E-13)

3.5.7 Information Provided by HWT for Proposals 1, 2, 3, 6, and 7

HWT indicated that it has acquired an option or, in the case of proposal 7, options to purchase the parcel or parcels on which the project would be located. HWT did not indicate that there would be any incremental costs for this site or sites beyond the purchase price. (E-1, E-13)

3.5.8 Information Provided by HWT for Proposal 8

HWT proposed to use land in the existing PG&E Round Mountain and Table Mountain Substations. HWT indicated that if it is selected by the ISO as the approved project sponsor, it would begin negotiations with PG&E to acquire the land rights for the project. HWT indicated that in the event it is unable to acquire land rights for the PG&E sites, it would develop the project on two other sites (previously described) adjacent or near to PG&E's Round Mountain and Table Mountain Substations for which HWT has already acquired options to purchase the land rights. HWT did not indicate that "co-locating" the project on existing PG&E property or developing the project on its proposed alternative sites would result in any incremental costs beyond the purchase price. (E-13)

3.5.9 Information Provided by LSPGC

LSPGC indicated that it has acquired options to purchase its preferred site and alternative site. LSPGC did not indicate that there would be any incremental costs for these sites beyond the purchase price. (E-13)

3.5.10 Information Provided by SEGG for Proposals 1 and 2

SEGG indicated that it has acquired options to purchase its preferred site. SEGG did not indicate that there would be any incremental costs for this site beyond the purchase price. (E-13)

3.5.11 Information Provided by SPT1

SPT1 indicated that it already has acquired options to purchase its preferred site. SPT1 did not indicate that there would be any incremental costs for this site beyond the purchase price. (E-13)

3.5.12 Information Provided by Tenaska

Tenaska indicated that it has acquired options to purchase its preferred site. Tenaska did not indicate that there would be any incremental costs for this site beyond the purchase price. (E-13)

3.5.13 Information Provided by TransCanyon

TransCanyon indicated that it has acquired an option to purchase the parcel on which it plans to construct the project and did not indicate that there would be any incremental costs associated with this parcel beyond the purchase price. (E-13)

3.5.14 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 the project is located in California and such experience will facilitate the timely, efficient, and effective undertaking of the project. However, in the case of this project, the land acquisition requirements are somewhat limited.

All six project sponsors for their twelve proposals have teams with substantial experience, including varying amounts of experience in acquiring land rights in California. Although some project sponsors have more experience than others, the ISO has considered the overall experience of the project sponsors and their teams and determined that there is no material difference among the twelve proposals of the six project sponsors with regard to this component of the factor, taking into account the land rights that project sponsors have already acquired. The ISO notes that HWT, for its proposals 1, 2, 3, 6, and 7, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon have already acquired an option to purchase the parcel on which they would locate their projects, and HWT has acquired an option to purchase a parcel for its alternate sites for its proposal 8.

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 transmission solution on existing rights-of-way.

None of the six project sponsors has indicated that it expects any incremental costs for any of its twelve proposals as a result of any use of existing rights-of-way for this project. Therefore, the ISO has determined that there is no material difference among the twelve proposals of the six project sponsors with regard to this component of the factor.

Overall Comparative Analysis

As discussed above, the ISO has determined that there is no material difference among the twelve proposals of the six project sponsors with regard to both the first component (the experience of the project sponsor and its team in acquiring rights of way) and the second component (whether the project sponsor would incur incremental costs for use of existing rights-or-way) of this factor. Consequently, the ISO has determined that there is no material difference among the twelve proposals of the six project sponsors with regard to 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 to ensure reliability in a major portion of the ISO controlled grid, as the ISO’s 2018-2019 transmission plan points out that adding voltage support in the area will mitigate high voltages after the Diablo Canyon Power Plant retires in 2025. A proposal that best satisfies this criterion will contribute significantly to ensuring that the project sponsor selected will develop the project in an efficient, cost-effective, and timely manner. 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

(Section 3 - General Project Information, QS-1, QS-3, QS-4, P-1, P-3, P-6, P-7, E-1, E-2, E-3, E-4, E-7, E-14a, E-14b, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii, S-2, S-3, S-4, T-2, T-3, T-4)

3.6.1 Information Provided by HWT for Proposals 1, 2, 3, 6, and 7

HWT proposed a project schedule that included an in-service date of December 1, 2023, which is six months earlier than the ISO's specified in-service date of June 1, 2024. In addition, HWT, for its proposals 1 and 2, indicated that it has approximately another six months of float in the schedule for its December 1, 2023 in-service date. HWT, for its proposals 3, 6, and 7, indicated that it has approximately another five months of float in the schedule for its December 1, 2023 in-service date. HWT indicated that given its planned in-service date, plus additional schedule float, it would still be able to meet the required in-service date of June 1, 2024 if the scheduled start were to be delayed by six months. (P-6)

3.6.2 Information Provided by HWT for Proposal 8

HWT proposed a project schedule that included an in-service date of June 1, 2023, which is twelve months earlier than the ISO's specified in-service date of June 1, 2024. In addition, HWT indicated that it has at a minimum another six months of float in the schedule for its June 1, 2023 in-service date. HWT indicated that given its planned in-service date, plus additional schedule float, it would still be able to meet the required in-service date of June 1, 2024 if the scheduled start were to be delayed by six months. (Introduction, QS-3, P-6)

3.6.3 Information Provided by LSPGC

LSPGC proposed a project schedule that included a “substantial completion” date of December 1, 2023, six months earlier than the ISO specified date of June 1, 2024. In addition, LSPGC indicated that its construction schedule has an additional 5 months of float. LSPGC stated that in the event of a six-month delay in the start date for the project or other unforeseen schedule delays that use up the 11 months of float built into the schedule, it could undertake measures to compress the construction schedule to meet its proposed schedule guarantee, such as releasing engineering and procurement activities earlier and performing tasks in parallel. (P-6, E-1, E-7)

3.6.4 Information Provided by SEGG for Proposals 1 and 2

SEGG proposed a “substantial completion” date of end of December 2023, approximately five months earlier than the ISO specified in-service date of June 1, 2024. SEGG indicated that if the start date were to be delayed by six months, it would implement measures to expedite project completion, such as collaboration with the ISO to expedite the signature process for the Approved Project Sponsor Agreement (APSA), commencing the environmental permitting process coincident with the project award, and seeking an early engagement with the CPUC to reduce uncertainty in the project schedule for obtaining a certificate of public convenience and necessity (CPCN) from the CPUC. (P-6, E-7)

3.6.5 Information Provided by SPT1

SPT1 proposed a project schedule that included a “substantial completion” date of March 1, 2024, three months earlier than the ISO specified in-service date of June 1, 2024. SPT1 indicated that if the start date were to be delayed by six months, it has built-in contingency measures to ensure that the project would meet the commercial operation date, such as coordination with PG&E earlier than in the schedule, acceleration of engineering, and early procurement of long lead-time material and equipment items. (QS-3, P-6, E-1, E-7)

3.6.6 Information Provided by Tenaska

Tenaska proposed a project schedule that included an “in service” date of April 1, 2024, two months earlier than the ISO specified in-service date of June 1, 2024. Additionally, Tenaska indicated that its potential streamlined permitting schedule approach could accelerate the development period by another four months. Tenaska indicated that if the project start date were to be delayed by six months, it could utilize potential project acceleration tools to bring the project back on schedule, such as using the two-month float in its construction schedule and four-month float in the schedule for its accelerated permitting process. (P-6, E-1, E-7)

3.6.7 Information Provided by TransCanyon

TransCanyon proposed a project schedule that would achieve the ISO’s specified in-service date of June 1, 2024. TransCanyon indicated that its schedule includes three months of float between the completion of the permitting and engineering process and the procurement and construction process, one month of contingency float during the procurement and construction phase, one month of float between the end of commissioning and testing, and one more month of float prior to the in-service date, resulting in a total of six months of total contingency. TransCanyon stated that these six months of total contingency would provide a buffer within the schedule to allow for recovery, particularly if the start date were to be delayed by six months. (P-6, E-1, E-7)

Ability to Meet Schedule

(Section 3 - General Project Information , QS-1, QS-3, QS-4, P-1, P-3, P-4, P-5, P-6, P-7, E-1, E-2, E-3, E-4, E-7, E-10, E-13, E-14a, E-14b, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii, S-2, S-3, S-4, T-2, T-3, T-4)

3.6.8 Information Provided by HWT for Proposals 1, 2, 3, 6, and 7

Past Performance

HWT provided schedule performance information for 72 transmission, generation, and substation projects completed within the past five years, including wind and solar substations, generation tie lines, and battery energy storage systems, along with their planned and actual in-service dates. (P-3) HWT indicated that all but 19 of the projects were completed earlier than the project target completion date. HWT indicated that one of these 19 projects was delayed by seven months due to archeological issues and the other 18 were completed less than three months late. HWT indicated that half of the delays resulted from interconnection or power purchase agreement execution issues, while it attributed the other half to delays in obtaining permits. (P-3)

Project Management and Team

HWT indicated that its core project management team has experienced professionals and subject matter experts, and it would draw upon the extensive resources of its affiliates for the project execution. (P-4)

HWT provided its project management process steps and actions it plans to take during its development and construction of the project, based on the model used by other NextEra companies, which included: (P-4)

Project Launch and Scoping,
Master Project Schedule,
Risk Identification and Mitigation,
Comprehensive Project Cost Estimate/Budget,
Project Execution Plan,
Monitor and Control Project Schedule,
Cost and Risks, and
Track and Report on Project Performance.

HWT indicated that its core team of professionals and subject matter experts would draw upon NextEra's matrixed organization of shared resources for the project execution and that the core team would be directed by HWT's senior management. HWT indicated that its executives have extensive utility and project management experience and would have ultimate decision-making authority for the project. (P-5)

Risk Management

HWT provided its current risk and issues log for the project, which identified major risks and obstacles to successful project completion on schedule and within budget. This document listed numerous risks considered by HWT. (P-7) In the log, HWT identified the specific risk, 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 planned or potential mitigation. (P-7)

HWT indicated that it has already completed an environmental and biological analysis at the proposed site location, as well as certain seasonal environmental surveys, and confirmed that the site is viable with minimal environmental impact, in particular that no protected species are present. HWT indicated that it also already has a wildfire mitigation plan approved by the CPUC that would avoid the need to develop and seek approval for a plan following project award. HWT also stated that it has acquired an option to purchase a suitable site or sites for the project. (QS-1)

Regarding HWT's ability to work on multiple projects simultaneously, HWT indicated that HWT and its affiliates have sufficient financial, technical, and human resources to successfully work on and deliver multiple projects at the same time. (P-7)

Financial Incentive

HWT's proposed project schedule provided for an in-service date of December 1, 2023, six months earlier than the ISO specified in-service date of June 1, 2024. HWT proposed a financial penalty for failure to meet the in-service date. (P-7)

3.6.9 <u>Information Provided by HWT for Proposal 8</u>

Past Performance

HWT provided the same information regarding past schedule performance for its proposal 8 as it did for its proposals 1, 2, 3, 6, and 7. See the information set forth in Section 3.6.8 regarding this aspect of HWT's proposal for its ability to meet schedule for its proposal 8.

Project Management and Team

HWT provided the same information regarding project management and team for meeting schedule for its proposal 8 as it did for its proposals 1, 2, 3, 6, and 7. See the information set forth in Section 3.6.8 regarding this aspect of HWT's proposal for its ability to meet schedule for its proposal 8.

Risk Management

HWT provided its current risk and issues log for the project, which identified major risks and obstacles to successful project completion on schedule and within budget. This document listed numerous risks considered by HWT. (P-7) In the log, HWT identified the specific risk, 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 planned or potential mitigation. (P-7)

HWT indicated that it also already has a wildfire mitigation plan approved by the CPUC that would avoid the need to develop and seek approval for a plan following project award. (P-6)

Regarding HWT's ability to work on multiple projects simultaneously, HWT indicated that HWT and its affiliates have sufficient financial, technical, and human resources to successfully work on and deliver multiple projects at the same time. (P-7)

HWT indicated that it proposes to "co-locate" the project on existing PG&E property in Round Mountain and Table Mountain Substations to minimize environmental impact and cost. HWT indicated that, given that the project would be located on existing PG&E substation property, HWT anticipates developing and constructing the project pursuant to a notice of construction to the CPUC, and not a CPUC permit to construct or CPCN. HWT indicated that it expects that the notice of construction process would reduce the overall schedule by about 12 months. HWT indicated that it would enter into negotiations with PG&E to secure the right to use the existing land in Round Mountain and Table Mountain Substations if the ISO selects it as the approved project sponsor. (E-1, E-10) HWT indicated that this proposed approach is consistent with comments made by CPUC commissioners in approving HWT's Suncrest SVC project and that the CPUC's authority to direct public utilities to make their existing rights-of-way available for public use would appear to derive from California Public Utilities Code § 762, which authorizes the CPUC to require coordination between public utilities and that they share costs. (QS-3) HWT indicated that if the proposal to purchase the PG&E property is unsuccessful, HWT also has acquired options to purchase suitable sites for the project immediately adjacent to the existing Round Mountain Substation and less than a half-mile from the existing Table Mountain Substation. HWT indicated that the expected schedule impact of this change would not exceed an additional 12 months beyond its proposed June 1, 2023 in-service date for the project, which would still meet the in-service date of June 1, 2024 set forth in the ISO Functional Specifications. (QS-3, E-1, E-10, E-13, Response to request for clarification)

Financial Incentive

HWT's proposed project schedule provided for an in-service date of June 1, 2023, twelve months earlier than the ISO specified in-service date of June 1, 2024. HWT proposed a financial penalty for failure to meet the in-service date. (Executive Summary)

3.6.10 <u>Information Provided by LSPGC</u>

Past Performance

LSPGC provided schedule performance information for five transmission line projects and five substation projects completed in the last five years. Of the five transmission line projects, two were completed projects and three are on-going projects. LSPGC indicated that both of the completed transmission line projects were completed on schedule. LSPGC indicated that of the five substation projects that were completed, three were completed on or ahead of schedule and one project was delayed by almost a year. (P-3)

Project Management and Team

LSPGC indicated that its project director would be the primary point of contact for the ISO and would be responsible for guiding LSPGC's day-to-day activities and overseeing all deliverables. LSPGC indicated that the project director would be supported by a highly qualified team of managers and subject matter experts with responsibilities for project execution within key project areas. (P-4)

LSPGC also provided an organization chart for development and construction and for operations, along with a list of staff for these roles. (P-5)

Risk Management

LSPGC indicated that it has already begun the process of planning and anticipating the project timelines, deliverables, and budgets, including the following steps:

- Executed exclusive option to purchase contracts for the preferred site and the alternative site;
- Advanced stage of negotiation of an engineering, procurement, and construction (EPC) services agreement with a firm for STATCOM equipment supply and construction;
- Executed a Master Services Agreement with a firm that would serve as the owner's engineer and would design the switchyard;
- Executed agreements with emergency response and maintenance contractors;
- Completed 30% engineering design;
- Prepared specifications for and competitively bid the following project components: electrical, civil, testing and commissioning, and STATCOM building;
- Identified and engaged California legal and environmental experts;
- Performed environmental field surveys (wetlands, cultural, and threatened and endangered species) on the preferred site and alternative site;
- Performed geotechnical borings; and
- Developed a detailed project budget and schedule based upon complete understanding of the preferred site and project requirements, which is informed by competitive bids for key materials and services. (P-4)

LSPGC identified risks in 40 areas regarding various aspects of project development and proposed mitigation measures. (P-7)

Regarding its ability to work on two projects simultaneously, LSPGC indicated that it has the resources to complete one or both on schedule and within budget, without negatively impacting either project. (P-7)

Financial Incentive

LSPGC offered a schedule guarantee in its proposal. If LSPGC does not meet an in-service date of June 1, 2024, LSPGC proposed that its return on equity be reduced by 2.5 basis points for every month that the project is delayed beyond June 1, 2024 up to a total of 30 basis points. As a result, LSPGC indicated that it would face financial penalties due to a lower equity return for the life of the project and increased allowance for funds used during construction (AFUDC) costs that may not be recoverable because of its binding capital cost cap if the project is delayed for reasons within its control. (P-6)

3.6.11 Information Provided by SEGG for Proposals 1 and 2

Past Performance

SEGG provided schedule performance information for one transmission line project (above 200 kV) and one substation project in last five years where it indicated that it has direct experience or an ownership interest. These projects are not complete and are currently under development and scheduled for completion in 2021. SEGG provided schedule performance information for fifteen projects completed by its team over the last five years. Of these projects, nine were completed on time and six were completed late. (P-1, P-3)

Project Management and Team

SEGG indicated that the project sponsor, through different contractors, would develop the plans executing the project. SEGG identified 15 major tasks and indicated that each task would be performed by a team led by experienced personnel. (P-4)

Risk Management

SEGG indicated that it has taken all available and prudent steps, including the following: (P-7)

- forming exclusive partnerships with technology providers, an EPC company, an engineering firm, and an operations and maintenance (O&M) services provider;
- working with the two land owners to secure options to purchase two parcels of land for locating the project, of which one is the preferred parcel, and the other would serve as the backup in case the project sponsor identifies a concern with the primary parcel during the development phase;
- having detailed dialogue with Tehama County and other key stakeholders in the area to ensure that SEGG has a clear understanding of the process to exit the land from Williamson Act encumbrance;
- assembling a team of highly skilled, established, and experienced professionals (development, environmental, and legal) for the project to ensure that every project related issue is identified early and addressed in a most efficient and cost-effective manner; and
- reviewing CPUC proceedings for the Suncrest SVC project and Williamson Act exit proceedings and project permitting process (challenges and actions) followed by a different developer and utilities (generation and transmission projects) in the area to get a realistic time estimate for building utility scale projects in this area.

SEGG identified risks in five areas related to various aspects of project development and proposed mitigation measures. (P-7)

Regarding its ability to work on two projects simultaneously, SEGG indicated that it and its partners in the project have the capability to complete both of the projects in accordance with the ISO's specifications and schedule. (P-7)

3.6.12 Information Provided by SPT1

Past Performance

SPT1 provided schedule performance information for seventeen substation and reactive support projects it and its team completed in the past five years. SPT1 indicated that sixteen of the seventeen projects were completed in the same year as planned. (P-3)

Project Management and Team

SPT1 provided its proposed management structure for the project, including the project director, project manager, construction manager, and on-site superintendents or lead representatives from each subcontractor. SPT1 indicated that the individuals selected to fulfill each of the roles within the project management structure are currently being evaluated based on forecasted project timeline and the experience and capabilities of available personnel. (P-5)

Risk Management

SPT1 described the following potential risks to the project schedule and its proposed efforts to mitigate those risks:

Delay in CPCN approval process: SPT1 indicated that it has already contracted with selected entities to assist with the CPUC CPCN process. SPT1 indicated that it would reach out to the CPUC as early as possible following award, would proceed with the required environmental studies and reviews on an expedited basis, and would work with the ISO to ask the CPUC to consider the reliability need date for the project.

Electrical Interconnection: SPT1 indicated that its design has minimized the scope of work required for the PG&E interconnecting lines by locating adjacent to PG&E's right-of-way and configuring the substation to minimize the cost, outages, and scope of PG&E's work. (P-7)

3.6.13 Information Provided by Tenaska

Past Performance

Tenaska provided schedule performance information for two transmission line projects (above 200 kV) and four substation projects completed in the last five years for which it indicated that it had direct experience. Tenaska indicated that all of the projects were completed ahead of schedule. (P-3)

Tenaska provided schedule performance information for seven STATCOM or SVC projects completed by its proposed STATCOM equipment manufacturer. Tenaska indicated that all of these projects were completed on time according to the agreed customer schedule.

Tenaska provided schedule performance information for seven switching station projects completed by its turnkey engineering, construction, and testing company. Tenaska indicated that all of these projects were completed on time. (P-3)

Project Management and Team

Tenaska indicated that its engineering and construction group along with its STATCOM EPC contractor and 500 kV switching station EPC teams would perform the project and construction manager role for the project. Tenaska indicated that the broader project team would be comprised of Tenaska employees drawn from its environmental services, operations, assessment management, accounting, public and government relations, finance, and insurance groups. In addition to internal resources, Tenaska indicated that it would selectively use third party consultants in the areas of specialty engineering, site supervision, quality audits, environmental compliance, legal, public relations, and insurance. (P-4)

Risk Management

Tenaska identified several risks.

Risk: The potential for unforeseen delays associated with PG&E's interconnection scope.

Proposed Mitigation: Tenaska indicated that its proposed project location is immediately adjacent to the existing 500 kV transmission lines with established and firm site control of the property that includes all of the project footprint, including property needed for the loop-in transmission lines, the substation, and the STATCOMs, thereby materially reducing any risk of potential added interconnection costs or delays associated with needing any additional site control or rights-of-way.

Risk: Potential for public opposition to the project.

Proposed Mitigation: Tenaska indicated that it has already met with management of the County of Tehama and has a good understanding of community interests and objectives that are incorporated into the project design.

Risk: Potential for unforeseen regulatory agency requirements.

Proposed Mitigation: Tenaska indicated that it has met with Tehama County management to discuss and understand what the requirements would be if the county were to be the lead agency.

Risk: Potential for the FERC ratemaking process to be contested and potentially extended.

Proposed Mitigation: Tenaska indicated that its schedule includes sufficient extra time for the FERC ratemaking process to be extended and not affect the overall schedule.

Risk: Potential that consultation with the U.S. Fish and Wildlife Service and Tehama County under the Endangered Species Act could cause project delays due to internal agency constraints, such as resource limitations.

Proposed Mitigation: Tenaska indicated that its proposed site has been strategically located to avoid potential sensitive biological impacts. Tenaska indicated that its environmental consulting firm conducted a preliminary biological screening of the site and found no indications of any endangered or sensitive species at the site or interconnection areas.

Risk: California Environmental Quality Act (CEQA) review delays.

Proposed Mitigation: Tenaska indicated that it plans to include all project elements in its project scope to be reviewed pursuant to CEQA, including the substation, STATCOMs, loop-in transmission lines, and connections to the existing 500 kV transmission system, thereby eliminating this concern.

Risk: Potential for concerns associated with any historic view shed, nearby traditional cultural properties, or other cultural resources.

Proposed Mitigation: Tenaska indicated that its proposed site has been strategically located to avoid potential impacts to sensitive cultural resources. Tenaska indicated that its environmental consulting firm conducted preliminary cultural screening of the site and found no indications of any known cultural resources at the site or interconnection areas.

Risk: Structure heights or locations in proximity to nearby public use airports may trigger Federal Aviation Administration review.

Proposed Mitigation: Tenaska indicated that its proposed site has been strategically located to avoid potential impacts to aviation and that there are no known aviation related limitations at this site.

Risk: Property rights acquisition.

Proposed Mitigation: Tenaska indicated that it has an executed, binding land purchase (or lease) option with the owner of record for the entire project siting needs.

Risk: The potential that unanticipated construction mitigation requirements identified by the affected agencies would constrain the construction schedule as it pertains to timing of activities, type of activities, etc.

Proposed Mitigation: Tenaska indicated that it met with County of Tehama management to discuss and understand what the requirements would be if the county were to be the lead agency for the project. Tenaska indicated that county approvals would be limited to a use permit and CEQA compliance and that no excessive mitigation requirements were discussed beyond typical construction mitigation plans.

Risk: Potential for project financing to cause schedule delays.

Proposed Mitigation: Tenaska indicated that it believes the project development plan put in place and the regulated return associated with the project would make it attractive to lenders.

Risk: Long lead-time equipment could be delayed, including major components like the STATCOM.

Proposed Mitigation: Tenaska indicated that the project construction schedule has built-in float of two months to offset any long lead-time equipment or material delays and still meet the ISO specified in-service date of June 1, 2024.

Risk: Fire risk.

Proposed Mitigation: Tenaska indicated that particular attention has been applied to fire prevention in the development and design of the project. Tenaska indicated that project location, security walls and fencing, and substantial fire break setbacks, as well as equipment selection and quality considerations, were all incorporated into the project and substantially reduce risk of fire. Additionally, Tenaska indicated that the project is located in very close proximity to the Paynes Creek fire station for quick response in the unlikely event of a fire in the area.

3.6.14 Information Provided by TransCanyon

Past Performance

TransCanyon indicated that its team members and their affiliates, with whom TransCanyon has contracted, have completed a significant number of projects. TransCanyon provided schedule performance information for four transmission line projects (above 200 kV) and three substation projects completed in the last five years, one of which included a STATCOM, where its affiliates APS and BHE have experience. TransCanyon indicated that all but one of the projects were completed on time. TransCanyon indicated that it would rely on the experience of its team members and parent companies for this project. (P-3)

Project Management and Team

TransCanyon indicated that it has already identified the team that would manage and execute this project. TransCanyon indicated that its approach to project management during construction would be governed by the project execution plan (PEP) that would be developed with its EPC contractor, upon selection by the ISO as the approved project sponsor. (P-4)

TransCanyon laid out the following plan for the different phases of the project:

- Application Phase,
- Permitting Phase,
- Project Development Phase,
- Construction and Commissioning Phase, and
- Operations Phase. (P-4)

TransCanyon proposed that PacifiCorp would assist in managing the operations and maintenance of the project. TransCanyon indicated that PacifiCorp has not provided similar operations and maintenance services for other unregulated assets or projects. TransCanyon also indicated that state regulators have not yet formally approved the performance of these operations services for unregulated assets for PacifiCorp. (QS-1)

TransCanyon indicated that it has entered into a Memorandum of Understanding (MOU) with PacifiCorp with regard to certain potential grid operations services that PacifiCorp may offer TransCanyon. TransCanyon indicated that in order for PacifiCorp to offer the services to TransCanyon, both PacifiCorp and TransCanyon must obtain exemptions from certain affiliate transaction rules of the CPUC. TransCanyon provided a list of these rules. TransCanyon indicated that both parties also may be required to comply with other requirements of applicable jurisdictions restricting or requiring notice of transactions between affiliates necessary for PacifiCorp to perform, and TransCanyon to receive, the services. TransCanyon provided a list of these other requirements from Oregon, Washington, Utah, Idaho, and Wyoming. TransCanyon indicated that it expects that the above regulatory approvals would be obtained in the ordinary course similar to the process by which NextEra obtained approval in the Suncrest SVC project CPUC proceeding. (QS-1)

Risk Management

TransCanyon indicated that it conducted desktop diligence as well as on-site field surveys to determine feasible substation locations and line connection routes, identify any significant technical or environmental and permitting concerns, and establish a viable plan upon which to develop the project. (P-4)

TransCanyon indicated that that in order to expedite the permitting phase, it has conducted biological and archaeological surveys and developed a draft Proponent's Environmental Assessment (PEA) for filing with the CPUC, along with supporting preliminary engineering, prior to submitting this proposal. TransCanyon indicated that it has also conducted initial meetings with Tehama County and the Public Advocates Office to inform and collect feedback regarding the project. (P-4)

TransCanyon indicated that it has executed a purchase option agreement for the proposed project site adjacent to both of the Round Mountain-Table Mountain 500 kV transmission lines. (P-4)

TransCanyon identified risks in seven areas related to various aspects of project development and proposed mitigation measures. (P-7)

3.6.15 <u>ISO Comparative Analysis</u>

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 project sponsors have proposed schedules for their twelve proposals that would meet the latest in-service date of June 1, 2024 specified in the ISO Functional Specifications. HWT proposed a project schedule for its proposal 8 that would complete the project twelve months earlier than the in-service date of June 1, 2024, with a minimum of four months of float in that schedule. HWT, for its proposals 1, 2, 3, 6, and 7, and LSPGC proposed a project schedule that would complete the project six months earlier than the in-service date of June 1, 2024, with at least an additional five months of float in their schedules. SEGG, for its proposals 1 and 2, proposed a project schedule that would complete the project five months earlier than the in-service date of June 1, 2024, and it described contingency measures that it could take to accelerate that schedule. SPT1 proposed a project schedule that would complete the project three months earlier than the in-service date of June 1, 2024, and it described contingency measures that it could take to ensure timely completion of the project. Tenaska proposed a project schedule that would complete the project two months earlier than the in-service date of June 1, 2024, and described a streamlined permitting approach to potentially accelerate the project schedule by four months, if necessary. TransCanyon proposed a project schedule that would complete the project on the latest in-service date of June 1, 2024, with six months of float in its schedule.

All six project sponsors for their twelve proposals indicated that that they could complete the project by the in-service date in the ISO Functional Specifications if the start date were to be delayed by six months.

The ISO considers all six project sponsors' schedules for their twelve proposals to 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 actions to be comparable.

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. 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 can be completed sooner than the ISO's specified in-service date of June 1, 2024, the ISO reserves the option to negotiate an earlier in-service date with the approved project sponsor when the ISO has better information regarding the potential benefits of achieving an earlier in-service date.

Based on the foregoing analysis, 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 could complete the project by the latest in-service date of June 1, 2024 specified in the ISO Functional Specifications. Thus, the ISO has determined that there is no material difference among the twelve proposals of the six project sponsors with regard to 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 the experience of both the project sponsor and its team members with projects comparable to this project in meeting schedules, including but not limited to the information in their proposed schedules and their past experience in constructing projects on schedule, performing project management, and accounting for risk management, as well as any other indicated factors that might impact the date of completion (either favorably or unfavorably).

Proposed Schedule

As discussed above, all six project sponsors have proposed schedules for their twelve proposals that meet the latest in-service date for the project of June 1, 2024 specified in the ISO Functional Specifications. In addition, the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, and SEGG, for its proposals 1 and 2, provide for a scheduled in-service date at least five months in advance of the date specified in the ISO Functional Specifications. The schedules proposed by SPT1, Tenaska, and TransCanyon are somewhat tighter, providing for project completion three, two, and zero months earlier, respectively, than the latest in-service date for the project of June 1, 2024 specified in the ISO Functional Specifications. The proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, and TransCanyon also include a minimum of five months of additional float in their schedules, as described above. SEGG, for its proposals 1 and 2, SPT1, and Tenaska did not describe any additional schedule float in their proposals, but they listed a series of measures to expedite the schedule if the start date of the project were to be delayed. All six project sponsors indicated that they could complete the project for their twelve proposals by the latest in-service date in the ISO Functional Specifications if the start date were to be delayed by six months. All of the project sponsors except SPT1 and Tenaska have proposed a combination of a scheduled project completion date and an amount of float in their project schedules that would amount to at least five months of total “cushion” in their schedules. SPT1’s scheduled project completion date, which is three months in advance of the latest in-service date, combined with no identified float in the project schedule, provides SPT1 with only three months of cushion in its schedule. Tenaska’s scheduled completion date, which is two months in advance of the latest in service date, combined with no additional float in the project schedule, provides Tenaska with only two months of cushion in its schedule. The ISO considers this small amount of cushion in SPT1’s and Tenaska’s schedules to place their proposals at a slight disadvantage relative to the proposals of the other project sponsors, particularly because this is a reliability-driven project for which completion by the specified in-service date is critical. If there was to be a delay, SPT1 and Tenaska would need take other actions to complete the project by the ISO specified in-service date.

Previous Experience

The project sponsors and their team members have different levels of experience with previous transmission line and substation projects. HWT, for its proposals 1, 2, 3, 6, 7, and 8, provided schedule performance information for 72 transmission line and substation projects, including wind and solar substations, generation tie lines, and battery energy storage systems. LSPGC provided schedule performance information for five transmission line and five substation projects. SEGG, for its proposals 1 and 2, provided schedule performance information for fifteen projects for its team and two projects of its own. SPT1 provided schedule performance information for seventeen substation and reactive support projects. Tenaska provided schedule performance information for two transmission line and eleven substation projects. TransCanyon provided information for four transmission line and three substation projects that were completed by its affiliates.

In terms of completing projects on schedule, the ISO considers HWT, for its proposals 1, 2, 3, 6 ,7, and 8, LSPGC, SPT1, Tenaska, and TransCanyon to have demonstrated a reasonable degree of success in meeting previous project schedules, although some project sponsors demonstrated more experience than others. SEGG, for its proposals 1 and 2, demonstrated relatively little recent experience in meeting project schedules. Out of the examples provided by SEGG, two projects had not yet been completed and had revised in-service dates, and six of the fifteen projects completed by its team were completed late. HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SPT1, Tenaska, and TransCanyon indicate that they have generally only experienced minor delays, and they provided reasonable explanations for the delays. When the ISO compared the number of projects that were delayed to the number of projects completed for HWT, LSPGC, SPT1, Tenaska, and TransCanyon, the ISO found that to be a small percentage for any project sponsor. Consequently, the ISO considers there to be no material difference among the recent experience of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SPT1, Tenaska, and TransCanyon in completing previous projects on schedule and considers their experience to be better than the experience described by SEGG, for its proposals 1 and 2, which consisted of no projects completed by SEGG on the last five years and six of fifteen projects completed late by its team.

Project Management and Team

The ISO considers all six project sponsors to have provided a reasonable approach to professional project management for their twelve proposals. All six project sponsors laid out detailed project management programs, as well as identifying the teams that would be working on each task of the project. In addition, the project managers or directors identified in each proposal have at least twenty years of experience, which the ISO considers sufficient.

TransCanyon indicated that it has entered into an MOU with PacifiCorp for certain potential grid operations services that PacifiCorp may offer TransCanyon. TransCanyon indicated that in order for PacifiCorp to offer the services, both PacifiCorp and TransCanyon must obtain exemptions of certain affiliate transaction rules of the CPUC and that both parties may be required to comply with other requirements of applicable jurisdictions restricting or requiring notice of transactions between affiliates. TransCanyon indicated that it expects that the above regulatory approvals would be obtained in the ordinary course.

Although the ISO considers the regulatory processes associated with obtaining these approvals to pose some small additional risk of potential delay to the project schedule that other project sponsors do not face because TransCanyon and PacifiCorp would have to obtain exemptions from the CPUC and comply with other requirements in five states where PacifiCorp operates, the ISO does not consider this additional hurdle significant enough to put TransCanyon at a significantly greater risk of schedule delay resulting from its choice of project team than any other project sponsor. This is the case in part because TransCanyon would primarily be using the services of PacifiCorp for operations and maintenance functions after the project would go into service, so the ISO anticipates that the time required to obtain regulatory approvals for its affiliate transactions with PacifiCorp shouldn’t have a significant impact on TransCanyon's project development schedule or in-service date.

Based on the foregoing analysis, the ISO considers that regarding project management and team there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon.

Project Risk and Management

The ISO considers all six project sponsors to have provided a thorough approach to identifying risks to the project schedule and possible mitigations for those risks for their ten proposals. All six project sponsors confirmed their ability to work on two projects simultaneously, if awarded both. All six project sponsors indicate that they have taken steps to reduce risk for their proposals.

HWT's primary site, for its proposal 8, is "co-located" on existing PG&E property, but HWT did not indicate that it has discussed this co-location with PG&E. As discussed above, this presents an additional risk regarding HWT's proposal to build at its primary site. Failure to obtain PG&E's agreement or CPUC authorization would require HWT to move the project to its backup site. Although HWT indicated that it anticipated that the expected schedule impact of this change would not exceed an additional 12 months beyond its proposed June 1, 2023 in-service date for the project, which would still potentially meet the in-service date of June 1, 2024 set forth in the ISO Functional Specifications, it presents a risk, particularly because HWT's proposal 8 does not incorporate all of the specific details associated with the project that would be built at the alternate site into the proposal.

The CPUC's authority referenced by HWT to direct a public utility to make its property available for public use would apply to all project sponsors, assuming the CPUC would use it. The ISO notes that regarding the Suncrest SVC project, the CPUC ultimately approved a solution that was outside of existing public utility property and that the ISO determined had the lowest cost cap and more robust binding cost containment measures.

Based on the foregoing analysis, the ISO considers the proposals of HWT, for its proposals 1, 2, 3, 6, and 7, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon to be comparable and slightly better than HWT's proposal 8 due to the risk associated with the potential failure to obtain approval from PG&E or the CPUC for co-locating the project on PG&E's property and having to significantly rework the project or obtaining agreement with PG&E to use its land.

Financial Incentive

The proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, and LSPGC include a financial penalty for failure to complete the complete the project in a timely manner. The ISO considers the financial penalty proposals to give these proposals an advantage over the proposals of SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon, which did not offer any type of financial consequences for failing to complete the project on schedule.

Overall Assessment

Overall, regarding past performance, project management and team, risk management, and financial incentives, and based on consideration of all of the aspects of the ability of the project sponsors to meet the latest in-service date of June 1, 2024 specified in the ISO Functional Specifications, including risk considerations and inherent schedule flexibility, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, and 7, and LSPGC and that they are better than the proposals of the other project sponsors with regard to this component of the factor because they have included financial penalties for late completion of the project and do not have identified risks regarding ability to meet the schedule.

The ISO has also determined that TransCanyon's proposal is better than the proposals of HWT, for its proposal 8, SEGG for its proposals 1 and 2, SPT1, and Tenaska with regard to this component. TransCanyon's proposal has six months of float in its project schedule and, unlike the proposals of SPT1 and Tenaska, does not need to take any additional actions to meet the ISO specified in-service date if there is a six month delay in the project start date. Also, TransCanyon's proposal does not present any unique risks like those that are part of HWT's proposal 8 to co-locate its facilities on PG&E land. In addition, TransCanyon has demonstrated more recent experience in meeting project schedules than SEGG. The ISO has concluded that there is no material difference among the proposals of HWT, for its proposal 8, SEGG, for its proposals 1 and 2, SPT1, and Tenaska with regard to the foregoing considerations for this component of the factor. HWT's proposal 8 includes financial penalties for late completion of the project, but it also faces the risk associated with the potential failure to obtain approval from PG&E or the CPUC for co-locating the project on PG&E's property. SEGG demonstrated less recent project completion experience for its proposals 1 and 2 and less schedule float than HWT's proposal 8, but more float than the proposals of SPT1 and Tenaska. The proposals of SPT1 and Tenaska have less float, but they present no unique project risks relative to HWT's proposal 8 and demonstrated more extensive recent project completion experience relative to SEGG's proposals 1 and 2.

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 HWT, for its proposal 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, and TransCanyon and that they are slightly better than the proposals of SPT1 and Tenaska, between which there is no material difference, with regard to the first component of this factor (proposed schedule). With regard to the second component (demonstrated ability to meet the proposed schedule), based on the foregoing analysis, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, and 7, and LSPGC and that those proposals are better than TransCanyon's proposal, which is slightly better than the proposals of HWT, for its proposal 8, SEGG, for its proposals 1 and 2, SPT1, and Tenaska, among which there is no material difference. Combining its analysis of these components, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, and 7, and LSPGC and that those proposals are better than TransCanyon's proposal, which is slightly better than the proposals of HWT, for its proposal 8, and SEGG, for its proposals 1 and 2, between which there is no material difference, and which are slightly better than the proposals of SPT1 and Tenaska, between which there is no material difference, with regard to this factor overall.

3.7 Selection Factor 24.5.4(e): The Financial Resources of the Project Sponsor and Its Team

(Section 3 - General Project Information, QS-2, QS-3, P-1, F-1 through F-14)

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.

Project sponsors provided information related to 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, 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 one 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.

3.7.1 Information Provided by HWT for Proposals 1, 2, 3, 6, 7 and 8

Project Financing Experience

HWT provided a list of NextEra's project financing experience in the past five years that included 29 transmission projects and 62 substation projects. (P-1)

HWT provided information from NextEra's development and finance experience for five representative projects with limited-recourse loans or letters of credit. HWT indicated that debt sources included commercial banks or private institutional investors. (P-1, F-11)

Project Financing Proposal

HWT indicated that it would draw 100% of its equity and debt funding requirements from HWT's corporate parent, NextEra, through NextEra's financing affiliate NEECH. HWT indicated that NEECH would provide needed guarantees to HWT and those would in turn be guaranteed by NextEra as provided for through a blanket guarantee arrangement between NEECH and NextEra. HWT indicated that execution of a guaranty would be dependent on the ISO selecting HWT as the approved project sponsor and the execution of a mutually agreeable APSA with the ISO. (F-2)

During development and construction, HWT indicated that NEECH would contribute equity and provide access to debt financing at commercially attractive rates. On or around the in-service date for the project, HWT indicated that it intends to convert the construction financing to long-term debt at commercially attractive rates provided by NEECH. (F-1)

HWT indicated that the project would be supported 100% through corporate parent debt and equity funding. HWT indicated that ratepayers would receive the benefit of a project constructed with strong equity support, without any risk of project-level leverage. HWT indicated that corporate parent funding would benefit ratepayers by avoiding unnecessary and costly third party transaction costs and providing the flexibility to complete the project under a range of possible scenarios (*e.g.*, construction delays, regulatory interventions, etc.). (F-14)

Financial Resources

HWT provided a letter from NextEra, signed by an officer of NextEra, indicating NextEra's financial assurance for the project. (F-2)

HWT provided NextEra's annual audited and quarterly unaudited financial statements for 2014-2019. HWT provided the following information from NextEra's latest annual audited financial statements: (F-3, F-4)

Total assets
Total liabilities
Net worth

Credit Ratings

HWT 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

HWT provided the following financial ratios based on NextEra's audited financial statements: (F-9, F-10)

Total assets/total projected project cost
Funds from operations (FFO)/interest coverage
FFO/total debt
Total debt/total capital

3.7.2 <u>Information Provided by LSPGC</u>

Project Financing Experience

LSPGC provided a list of five transmission and four substation projects that its ultimate parent, LS Power, financed in the past five years. LSPGC provided information regarding LS Power's financing of five representative projects, two of which were just outside the five-year period, and indicated that the projects were financed with multiple equity-to-debt contributions using a variety of debt sources, including project-specific financing through a number of commercial banks. (P-1, F-11)

Project Financing Proposal

LSPGC indicated that it would rely on LS Power, its ultimate parent, for capital funding for this project. LSPGC indicated that LS Power would provide the equity financing for the development of the project but that LSPGC would be responsible for arranging the debt associated with the construction and operations of the project and would service the debt after placing the project into service. LSPGC indicated that it would convert debt used during development and construction or issue new long-term, project-specific financing supporting operations. LSPGC provided evidence of LS Power's financial assurances to LSPGC in the form of a written guarantee. (F-1, F-2, F-5)

To provide further evidence of financial support for the project, LSPGC 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-5)

Financial Resources

LSPGC provided a letter from LS Power, signed by an officer of LS Power's general partner, indicating LS Power's financial support for the project. (F-2)

LSPGC provided LS Power's annual audited and quarterly unaudited financial statements for 2014-2019. LSPGC provided the following information from LS Power's latest annual audited financial statements: (F-3, F-4)

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)

LS Power provided annual and quarterly unaudited financial statements to the ISO for the years 2014-2019.

Financial Ratio Analysis

LSPGC provided the following financial ratios based on LS Power's audited financial statements: (F-9, F-10)

Total assets/total projected project cost
FFO/interest coverage
FFO/total debt
Total debt/total capital

3.7.3 <u>Information Provided by SEGG for Proposals 1 and 2</u>

Project Financing Experience

SEGG listed one transmission and one substation project that it financed in the last five years. SEGG provided information on financing experience for three representative projects, two of which were well outside of the five-year period, of non-recourse construction with debt sourced from institutions. (P-1, F-11)

Project Financing Proposal

SEGG indicated that it would create a special purpose entity as an affiliate for purposes of developing the project. SEGG indicated that the special purpose entity would be managed by SEGG through SEIF III and affiliated investment vehicles specifically to finance, construct, own, maintain, and operate the project. (Section 3 and F-1)

SEGG stated that the financial structure for construction and working capital would incorporate a special purpose vehicle tranche of debt at the project level. SEGG indicated that the construction loan would be refinanced by institutional investors through a private placement bond. (F-12)

To provide further evidence of financial support for the project, SEGG provided letters of support from three commercial banks. The letters are clear that they are non-binding and should not be construed as a commitment to finance the project. (F-2)

Financial Resources

SEGG indicated the project sponsor would rely on SEGG's existing funds or affiliated investment vehicles financial backing of the project. SEGG provided a letter indicating that SEGG would provide a financial guarantee on behalf of SEIF III. SEGG stated that its parent has sufficient uncommitted capital through SEIF III to support the construction of the project and any potential liabilities. (F-2)

SEGG provided the following information based on quarterly unaudited financial information for 2019 within a letter in lieu of financial statements for 2019.

Total assets
Total liabilities
Net worth

Credit Ratings

SEGG stated that SEIF III does not have a credit rating. (F-6)

Financial Ratio Analysis

The ISO calculated the following financial ratios based on 2019 unaudited quarterly financial information:

Total assets/total projected project cost
Total debt/total capital

3.7.4 Information Provided by SPT1

Project Financing Experience

SPT1 provided a list of SPC's project financing experience that included 22 transmission and 40 substation projects within the last five years. The proposal indicated that SPC's projects were funded using balance sheet financing without issuance of public debt. (P-1, F-11)

Project Financing Proposal

SPT1 indicated it that it would rely on SPC to meet the financial requirements for the project. (F-2) SPT1 provided a letter of financial assurance from SPC stating that SPC will issue a parent guarantee to ensure that SPT1 has sufficient resources to meet its financial obligations. (F-4)

SPT1 stated that SPC will contribute 100% of the equity to fund the project and that SPT1 is not expected to have any debt but could access quickly the capital and bank markets if a need arises. (F-1, F-2)

Financial Resources

SPT1 indicated that it is relying on SPC to meet the financial requirements for the project and that SPC is a large U.S. wholesale energy provider with substantial access to capital. (F-2)

SPT1 provided SPC's audited financial statements for the past five years and quarterly unaudited financial statements for 2014-2019. SPT1 provided the following information from SPC's latest annual audited financial statements: (F-3, F-4)

Total assets
Total liabilities
Net worth

Credit Ratings

SPT1 provided the following credit ratings and associated credit reports for SPC: (F-6):

S&P - BBB+
Moody's - Baa1
Fitch - BBB+

Financial Ratio Analysis

SPT 1 provided the following financial ratios based on SPC's audited financial statements: (F-9, F-10)

Total assets/total project costs
FFO/interest coverage
FFO/total debt
Total debt/total capital

3.7.5 <u>Information Provided by Tenaska</u>

Project Financing Experience

Tenaska provided a list of Tenaska Energy's project financing experience that included three transmission and five substation projects within the last five years. Tenaska provided information from Tenaska Energy's finance experience for five representative projects and indicated that Tenaska Energy's debt sources for these projects included commercial banks. (P-1, F-11)

Project Financing Proposal

Tenaska indicated that Tenaska Energy and Tenaska Holdings, indirect parent entities of Tenaska, would create a jointly owned special purpose entity to own the assets of the project during the construction and operating period. (F-2)

Tenaska indicated that the special purpose entity would obtain and service any debt financing that would be required for the purpose of developing, designing, constructing, and operating the project. Tenaska indicated that financing would also be supported by equity commitments and guarantees provided by Tenaska Energy, Tenaska Holdings, and, if applicable, any equity co-sponsors identified by Tenaska. (Section 1)

Tenaska indicated that the parent entities would contribute 100% of the project equity and that project debt would be financed through the capital markets. (F-1, F-5)

Financial Resources

Tenaska indicated that the special purpose entity created for the project would rely on Tenaska Energy and Tenaska Holdings to meet the financial requirements of the project, as they would be the indirect parents of the jointly owned special purpose entity. (F-2)

Tenaska provided combined audited annual financial statements for Tenaska Energy and Tenaska Holdings for the past five years. (F-3)

Credit Ratings

Tenaska indicated that Tenaska's parent entities are not rated by any credit rating agencies. (F-6)

Financial Ratio Analysis

Tenaska reported the following financial ratios based on Tenaska Energy's audited financial statements: (F-9)

Total assets/total project costs
FFO/interest coverage
FFO/total debt
Total debt/total capital

3.7.6 <u>Information Provided by TransCanyon</u>

Project Financing Experience

TransCanyon provided a listing of its parent companies' project financing experience that included four transmission and four substation projects within the last five years. (P-1)

TransCanyon provided information about BHE's and PNW's financing experience, which included both corporate and project-based financing. Project-based financing included five projects, and corporate-based financing included four projects. Debt was sourced from private placement or other incremental debt facilities. (P-1, F-11)

Project Financing Proposal

TransCanyon indicated that it would rely on its ultimate parent companies – BHE and PNW – to meet the financial requirements for the project and that each is a large utility holding company with substantial access to capital. (F-2) TransCanyon provided a written performance guarantee from its two parent companies, PNW and BHE, providing the ISO joint and several assurance by the parent companies to perform the obligations of the project contract. (QS-2)

TransCanyon indicated that BHE and PNW would fund 100% of the project equity requirements from existing and future liquidity sources, including internally generated cash, credit facilities, and debt and equity issuances as appropriate. (F-2)

TransCanyon also provided a letter from Western Area Power Administration (WAPA) regarding its Transmission Infrastructure Program showing that WAPA is proceeding with the review and evaluation of the project for purposes of determining whether or not to enter into a subsequent agreement with TransCanyon to engage in specific project development work. TransCanyon indicated that the WAPA Transmission Infrastructure Program would be the most cost-effective option for customers. (F-12)

TransCanyon indicated that it intends to utilize the WAPA Transmission Infrastructure Program funds for a large portion of the project's capital needs, including initial working capital. TransCanyon indicated that, prior to financial close, BHE and PNW would fund 100% of the capital (for licensing, permitting, design, land acquisition, and limited notice-to-proceed contractor releases). TransCanyon indicated that upon financial close WAPA and BHE/PNW would fund the capital needed to complete and commission the project. TransCanyon indicated that funds would be drawn quarterly during construction and taken out upon commercial operation with one or more long-term bonds with maturities up to 30 years. TransCanyon indicated that all equity would come from cash infusions from BHE and PNW pro-rata to their respective ownership interests (50/50). (F-12)

TransCanyon indicated that its proposal would be firmly backed by a guaranty from its ultimate parent companies – BHE and PNW. (QS-3)

Financial Resources

TransCanyon indicated that it is relying on its parent companies (BHE and PNW) to meet the financial requirements for the project and that each is a large utility holding company with substantial access to capital. (F-2)

TransCanyon provided BHE's and PNW's annual audited and quarterly unaudited financial statements for 2014-2019. TransCanyon provided the following information from both BHE's and PNW's latest annual audited financial statements:

Total assets
Total liabilities
Net worth

Credit Ratings

TransCanyon provided the following credit ratings and associated credit rating reports for BHE and PNW: (F-6)

Moody's: BHE A3; PNW A3
S&P: BHE A; PNW A-

Financial Ratio Analysis

TransCanyon provided the following financial ratios based on BHE's and PNW's audited financial statements: (F-9; F-10)

Total assets/total projected project cost
FFO/interest coverage
FFO/total debt
Total debt/total capital

3.7.7 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 largely considered the project sponsors' representations. In addition, the ISO has considered each project sponsor's audited financial statements as well as 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.*, an ultimate parent) for financial support on the project, the ISO has 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 between project sponsors with regard to 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 and considering the project cost estimates. Consequently, this comparative analysis relies in large part on minor degrees of difference.

Project Financing Experience

Based upon the information provided and representations by the project sponsors, the ISO has determined that, over the past five years, HWT and SPT1 identified considerably more transmission project and project financing experience than LSPGC, SEGG, Tenaska, and TransCanyon. Although LSPGC, Tenaska, and TransCanyon identified less transmission project financing experience than HWT and SPT1, their financing experience exceeded the experience of SEGG during the past five years. Nevertheless, SEGG demonstrated some project financing experience.

The ISO has concluded that even though HWT and SPT1 demonstrated more transmission project financing experience than LSPGC, Tenaska, and TransCanyon, LSPGC, Tenaska, and TransCanyon demonstrated more transmission project financing experience than SEGG, in the past five years both LSPGC and SEGG, sufficiently demonstrated their ability to secure project financing for this project. Consequently, given the cost of this particular project, the ISO considers the project financing experience of all six project sponsors for their twelve proposals to be sufficient that there is no material difference among them with regard to the extent to which their project financing experience has a bearing on their ability to finance this particular project.

Project Financing Proposal

Each project sponsor proposes to rely to some extent on its ultimate parent for financing and/or access to the capital markets. HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, and SPT1 provided letters of financial support for the project from their ultimate parents, and Tenaska and TransCanyon also indicated that they would be relying on their parent companies to meet the financial requirements for the project. The project sponsors' funding targets are within a narrow range of each other with respect to debt and equity.

TransCanyon is the only project sponsor that indicated it may finance a portion of the project debt using WAPA's Transmission Infrastructure Program. TransCanyon has received a memorandum of understanding showing WAPA's support to continue its review and evaluation of the project, but the memorandum of understanding is clear that it is not a commitment to fund the project. If WAPA Transmission Infrastructure Program funding of the project is unavailable, TransCanyon would pursue alternative financing of the project.

Based on all six project sponsors' reliance on parent funding and access to the capital markets, the ISO finds no material difference in their funding proposals for their twelve proposals.

Financial Resources

Based on the project sponsors' 2018 annual financial statements, 2019 quarterly financial reports, and other financial information provided, all six project sponsors exhibit sufficient financial strength and resources to complete this particular project. The ISO calculated a tangible net worth for the project sponsors and has concluded that HWT, SPT1, Tenaska, and TransCanyon have shown higher net worth and tangible net worth than LSPGC and SEGG over the past five years. 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. Recent and past project financing experience indicates that both LSPGC and SEGG have developed banking relationships as evidenced by various banks providing support for this project. Consequently, the ISO considers LSPGC and SEGG, for its two proposals, to have sufficient financial resources to complete this project, although HWT, for its six proposals, SPT1, Tenaska, and TransCanyon are better with regard to this consideration.

Credit Ratings

HWT, SPT1, and TransCanyon 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, SEGG, and Tenaska's parent 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.

The ISO calculated a Moody's Analytics equivalent rating for the project sponsors to the extent feasible given the information they provided. Given the information provided and based on the ISO's ability to calculate Moody's Analytics estimated default frequency and the resulting Moody's Analytics equivalent rating for the past five years, the ISO considers HWT, for its six proposals, SPT1, Tenaska, and TransCanyon stronger than LSPGC and SEGG, for its two proposals, between which the ISO can identify no material difference, in this regard.

Financial Ratio Analysis

Financial ratios provide the ISO insight into a project sponsor's ability to pay interest and service long-term debt out of cash flow from its operating activities as well as how leveraged a company is in terms of its debt obligations. However, SEGG 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.

HWT, SPT1, Tenaska, and TransCanyon have better financial ratios than LSPGC and SEGG, to the extent the ISO was able to calculate ratios for SEGG. As a result, the ISO considers HWT, for its six proposals, SPT1, Tenaska, and TransCanyon to be stronger than LSPGC and SEGG, for its two proposals, between which the ISO can identify no material difference, in this regard.

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. The ISO considers HWT, for its six proposals, SPT1, Tenaska, and TransCanyon to have an advantage over LSPGC and SEGG, for its two proposals, in the areas of financial resources, credit ratings, and financial ratio analysis. Further, the ISO considers the differences among the project sponsors and their proposals with regard to project financing experience and project financing proposals to be insignificant compared to the other differences among the project sponsors and their proposals. 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, for this particular factor, there is no material difference among HWT, for its six proposals, SPT1, Tenaska, and TransCanyon for their proposals and all four project sponsors and their proposals are slightly better than LSPGC and SEGG and their proposals, between which the ISO can identify no material difference, with regard to 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."

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

(Section 3 - General Project Information, QS-1, QS-4, P-1, P-6, P-8, E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9a, E-9b, E-9bi, E-9bii, E-9c, E-10, E-14a, E-14b, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-2, S-5, T-1)

3.8.1 Information Provided by HWT for Proposals 1, 2, 3, 6, and 7

HWT indicated that it plans to file an application for a permit to construct and a PEA with the CPUC for the project. HWT provided an environmental licensing plan for the project that thoroughly analyzed the potential impacts and could provide the foundation of a PEA. (E-1)

HWT indicated that its internal staff (staff of NEER) has permitted 10 transmission and substation projects within the last five years, including three in California. HWT indicated that its environmental permitting consultant has permitted (on behalf of the developer) 18 projects, including solar and wind generation facilities, in California. HWT indicated that its legal team has provided legal support for permitting projects in California. (E-3, E-14a, E-14b, E14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii)

3.8.2 Information Provided by HWT for Proposal 8

HWT indicated that it plans to file a notice of construction and advice letter with the CPUC for the project and that because its proposed sites have already undergone review under CEQA, no additional environmental permitting would be required. (E-1, E-6)

HWT indicated that its internal staff (staff of NEER) has permitted 10 transmission and substation projects within the last five years, including three in California. HWT indicated that its environmental permitting consultant has permitted (on behalf of the developer) 18 projects, including solar and wind generation facilities, in California. HWT indicated that its legal team has provided legal support for permitting projects in California. (E-3, E-14a, E-14b, E14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii)

3.8.3 Information Provided by LSPGC

LSPGC indicated that it plans to seek authorization from, and file a PEA with, the CPUC for the project, in which case the CPUC would act as the CEQA lead agency. LSPGC provided a critical issues analysis that could form the basis of the PEA for the project, which thoroughly analyzed the potential impacts. In addition, LSPGC indicated that it expects to apply for a U.S. Army Corps of Engineers wetland permit and a California Department of Fish and Wildlife streambed alteration agreement for impacts to an ephemeral stream located on site. (E-1, QS-3)

LSPGC provided a list of six transmission line projects that it permitted in the last five years, one of which was located in California. LSPGC also provided a list of ten substation projects for which it performed permitting activities in the last five years, none of which was in California. LSPGC indicated that its environmental consultant has provided permitting support for 23 transmission line projects, 14 of which were in California, and 18 substation projects, 14 of which were in California. (E-14, E-15)

3.8.4 Information Provided by SEGG for Proposals 1 and 2

SEGG indicated that it would file an application for a CPCN and submit a PEA to the CPUC. SEGG listed other state discretionary permits that it would obtain for the project; including the following: Regional Water Quality Control Board Section 401 permit and storm water permit and California Department of Fish and Wildlife streambed alteration permit and Section 2081 incidental take permit. SEGG also noted the requirement for a special use permit from Tehama County. (E-6, E-9)

SEGG indicated that it has provided permitting for one project that is currently under development in California. SEGG indicated that its two environmental consultants have provided permitting support for eight California projects and four projects elsewhere within the last five years. (E-3) SEGG indicated that its legal consultant has provided permitting support for two projects in California and three projects elsewhere. (E-3)

SEGG indicated that its affiliates have permitted six generation projects in the last five years, none of which was in California. (E-14, E-15)

3.8.5 Information Provided by SPT1

SPT1 indicated that it would seek approval from the CPUC and other regulatory agencies for permitting the project by submitting a PEA along with a biological technical report and supporting protocol surveys, an archaeological report, an air quality/greenhouse gas report, and analyses of noise, aesthetics, traffic, and other potential project impacts.

SPT1 provided information regarding its environmental permitting experience for one California project and indicated that its environmental consultant has provided permitting support for two projects in California. (E-1, E-3, E-14, E-15)

3.8.6 Information Provided by Tenaska

Tenaska indicated that it would file an application for a land use permit with Tehama County and that Tehama County would be the CEQA lead agency. Tenaska listed the following other state permits: Regional Water Quality Control Board Section 401 permit, storm water permit, and storm water pollution prevention plan, California Department of Fish and Wildlife streambed alteration agreement, and County of Tehama Air Pollution Control District permits. Tenaska indicated that the CPUC may deny any county jurisdiction and require a permit to construct and a PEA. Tenaska indicated that if the CPUC were to require filing of an application for a permit to construct, Tenaska’s schedule and budget would not be affected.

Tenaska provided a list of recently permitted projects, including three in California. Tenaska indicated that its environmental consultant has provided permitting for nine California projects and that its legal consultant has provided support to Tenaska on five projects in California and several other projects elsewhere. (E-1, E-4, E-7, E-14))

3.8.7 Information Provided by TransCanyon

TransCanyon indicated it plans to file a CPCN application and PEA with the CPUC for the project. TransCanyon provided what is an essentially a draft PEA for the project, which thoroughly analyzed the potential impacts of the project. TransCanyon indicated that it would also file a Transmission Infrastructure Program application with WAPA, which would trigger a National Environmental Policy Act review, and that the CEQA and National Environmental Policy Act reviews would be done concurrently. (E-1, E-7)

TransCanyon indicated that it has already completed biological and archaeological field studies for the project and met with Tehama County to discuss any local permitting that may be required. TransCanyon indicated that WAPA would prepare an environmental assessment for the project in compliance with and in consideration of federal statutes, regulations, and guidelines. (E-5)

TransCanyon indicated that it has permitted six transmission line projects and five substation projects in the last five years. TransCanyon indicated that four of the transmission lines and three of the substations were permitted in California. TransCanyon also included information for its permitting consultant, noting that it has permitted eight substations in California in the last five years. (E-1. E-3, E-14, E-15)

Engineering Qualifications and Experience

(Section 3 - General Project Information , QS-1, QS-4, QP-1, QP-2, P-1, P-2, P-3, P-4, P-6, S-1, S-2, S-3, S-4, S-6, S-7, S-8, S-9, S-10, T-1, T-2, T-3, T-4, T-6, T-7, T-8, T-9, T-11, T-13, O-9 (T items as appropriate to the proposed project))

3.8.8 Information Provided by HWT for Proposal 1

HWT provided a detailed description of the STATCOM, consisting of two independent blocks of +/- 266 MVAr, and a substation with three breaker-and-one-half (BAAH) bays to terminate the Round Mountain-Table Mountain 500 kV transmission lines. HWT indicated that room would be provided for two future BAAH bays. (S-1) HWT indicated that it would use Power Line Carrier, fiber, or microwave for protection communication. (S-9) HWT indicated that it would provide blast walls and a solid perimeter wall for the project. (S-6, S-11)

HWT provided an extensive list of projects that are ongoing or that have been completed for which it and its potential team have performed engineering or design, including 26 transmission line projects, two in California, 104 substation projects from four potential firms, many in California, and 19 battery storage projects, none in California. (P-1, S-4) HWT identified a primary firm as the engineer of record and three other firms that it would consider for EPC services. HWT identified five other firms that it would consider as potential equipment manufacturers; HWT provided resumes for primary engineering firm individuals. HWT indicated that it prefers to competitively bid major contracts after award of the project. (S-2)

HWT indicated that its primary engineering firm and two of its other potential contractors have provided engineering or design services for projects in California, three potential STATCOM EPC contractors have provided engineering or design services for projects in the United States, and two other potential STATCOM EPC contractors have provided engineering or design services for projects that were all outside the United States. (S-3)

HWT indicated that NextEra has worked with all the firms, except one substation EPC firm and one STATCOM EPC firm, on previous projects in the United States. (S-4)

HWT provided a design criteria and detailed list of design standards and codes for the STATCOM. (S-6, S-7)

3.8.9 Information Provided by HWT for Proposal 2

HWT provided a detailed technical description of the STATCOM, consisting of two independent blocks, each block containing two +/-133 MVAr units, and a substation with three breaker-and-one-half (BAAH) bays to terminate the Round Mountain-Table Mountain 500 kV transmission lines. HWT indicated that room would be provided for two future BAAH bays. (S-1) HWT indicated that it would use Power Line Carrier, fiber, or microwave for protection communication. (S-9) HWT indicated that it would provide blast walls and a solid perimeter wall for the project. (S-6, S-11)

HWT provided the same information regarding the engineering and design experience of it and its team for its proposal 2 as it did for its proposal 1. See the information set forth in Section 3.8.8 regarding this aspect of HWT's proposal for its engineering qualifications and experience for its proposal 2.

HWT provided a design criteria and detailed list of design standards and codes for the STATCOM. (S-6, S-7)

3.8.10 Information Provided by HWT for Proposal 3

HWT provided a detailed technical description of the facilities, consisting of two independent dynamic reactive power systems, each composed of one three-phase STATCOM voltage source converter system rated ±236 MVAr and one 30 MW/37.5 MVA battery energy storage system with Q-priority. HWT indicated that the two 30 MW/60 MWh battery energy storage system facilities would each consist of 12 individual sets of 2.5 MW/4.2 MWh, 1500V DC battery banks coupled with a 5.5 MVA 1500V DC/480V AC power conversion unit (inverter). HWT indicated that the batteries would be sized to account for system aging degradation and to provide rated output at the point of common coupling, and would be rated as a two-hour MW energy capacity system. HWT provided a technical discussion of the capabilities of the battery energy storage system and STATCOM at the extreme ends of the specified voltage boundaries. HWT indicated that the design would include a substation with three breaker-and-one-half (BAAH) bays to terminate the Round Mountain-Table Mountain 500 kV transmission lines. HWT indicated that room would be provided for two future BAAH bays. (S-1) HWT indicated that it would use Power Line Carrier, fiber, or microwave for protection communication. (S-9) HWT indicated that it would provide blast walls and a solid perimeter wall for the project. (S-6, S-11)

HWT provided an extensive list of projects that are ongoing or that have been completed for which it and its potential team have performed engineering or design, including 26 transmission line projects, two in California, 104 substation projects from four potential firms, many in California, and 19 battery storage projects, none in California. (P-1, S-4) HWT identified a primary firm as the engineer of record and three other firms that it would consider for EPC services. HWT identified five other firms that it would consider as potential equipment manufacturers and four firms for batteries and inverters; HWT provided resumes for primary engineering firm individuals. HWT indicated that it prefers to competitively bid major contracts after award of the project. (S-2)

HWT indicated that its primary engineering firm and two of its other potential contractors have provided engineering or design services for projects in California, two potential EPC contractors, two battery firms, and two inverter firms have provided engineering or design services for projects in the United States, and three other potential EPC contractors have provided engineering or design services for projects that were all outside the United States. (S-3) HWT indicated that NextEra has worked with all the firms, except one substation EPC firm, one STATCOM EPC firm, and one inverter firm, on previous projects in the United States. (S-4)

HWT provided a design criteria and detailed list of design standards and codes for the STATCOM. (S-6, S-7)

3.8.11 <u>Information Provided by HWT for Proposal 6</u>

HWT provided a detailed technical description of the STATCOM, consisting of two independent blocks of +/- 266 MVAr, and a substation with three breaker-and-one-half (BAAH) bays to terminate at the Round Mountain-Table Mountain 500 kV transmission lines. HWT indicated that room would be provided for two future BAAH bays. (S-1) HWT indicated that it would provide blast walls and a solid perimeter wall for the project. (S-6, S-11) HWT indicated that PG&E would be required to construct four 500 kV transmission circuits to connect and loop the 500 kV transmission lines from Round Mountain Substation to the STATCOM switchyard. HWT provided detailed information on the underground cable connections and termination and indicated that to match the capacity of the existing overhead 500 kV circuit, the underground connection would require two 5,000 kcmil copper cables per phase. (S-1)

HWT provided the same information regarding the engineering and design experience of it and its team for its proposal 6 as it did for its proposal 1. See the information set forth in Section 3.8.8 regarding this aspect of HWT's proposal for its engineering qualifications and experience for its proposal 6.

HWT provided a design criteria and detailed list of design standards and codes for the STATCOM. (S-6, S-7)

3.8.12 <u>Information Provided by HWT for Proposal 7</u>

HWT provided a detailed technical description of the STATCOM, consisting of two independent ±281 MVAr units. HWT indicated that one STATCOM would be connected to the north end of the Round Mountain Substation 230 kV bus and one to the south end of the Table Mountain Substation 230 kV bus by 230 kV underground transmission lines. HWT indicated that at Round Mountain Substation a second 500/230 kV transformer would be added and that the 230 kV bus would be extended to accommodate this new transformer, the connection of HWT's STATCOM, and the expansion of the 500 kV ring bus to a full three-bay BAAH configuration, all by PG&E. HWT indicated that at Table Mountain Substation a second 500/230 kV transformer would be added and that the 230 kV bus would be extended to accommodate this new transformer, the connection of HWT's STATCOM, and the addition of a circuit breaker to the center bay for the new transformer, all by PG&E. HWT indicated that it would provide blast walls and a solid perimeter wall for the project. (S-6, S-11) HWT indicated that the point of demarcation would be the 230 kV riser structure outside each PG&E substation and that HWT would provide fiber between the STATCOM and the riser structures. HWT indicated that PG&E would install a new 230 kV substation dead end structure and string the bus span to the riser structure in both substations. (S-1)

HWT provided an extensive list of projects that are ongoing or that have been completed for which it and its potential team have performed engineering or design, including 26 transmission line projects, two in California, 104 substation projects from four potential firms, many in California, and 19 battery storage projects, none in California. (P-1, S-4) HWT identified a primary firm as the engineer of record and three other firms that it would consider for EPC services. HWT identified five other firms that it would consider as potential equipment manufacturers; HWT provided resumes for primary engineering firm individuals. HWT indicated that it prefers to competitively bid major contracts after award of the project. (S-2)

HWT indicated that its primary engineering firm and two of its other potential contractors have provided engineering or design services for projects in California, three potential STATCOM EPC contractors have provided engineering or design services for projects in the United States, and two other potential STATCOM EPC contractors have provided engineering or design services for projects that were all outside the United States. (S-3) HWT indicated that NextEra has worked with all the firms, except one substation EPC firm and one STATCOM EPC firm, on previous projects in the United States. (S-4)

For the underground transmission lines, HWT proposed two 230 kV underground transmission circuits, one from Round Mountain Substation to the STATCOM site east of Round Mountain Substation and the second from Table Mountain Substation to a STATCOM located to the west of Table Mountain Substation. HWT identified a 230 kV riser structure outside the substation as the point of demarcation. HWT indicated that PG&E would undertake all required work inside the perimeter of Round Mountain Substation and Table Mountain Substation. (T-10) HWT indicated that it would be responsible for all design and construction activities and would be supported by NextEra's internal engineering and construction and integrated supply chain department. HWT indicated that it would conduct a full request for proposal for the transmission line EPC contractor. HWT indicated that it would issue the request for proposals to firms including, but not limited to, three identified firms. HWT indicated that it would consider a primary firm for the manufacture and installation of the 230 kV transmission lines cable. HWT indicated that it has contracted with a primary engineering firm for preliminary transmission line design. (T-2) HWT provided a list of projects completed or ongoing in the past five years for its potential firms for engineering or design that included 28 projects, including projects in California, and 12 projects for another potential engineering and design firm with projects in the United States, and three projects for its primary firm for the manufacture and installation of the 230 kV underground cable circuits, including projects in California. (T-3, T-4)

HWT provided a design criteria and detailed list of design standards and codes for the STATCOM and underground transmission lines. (S-6, S-7, T-5, T-6, T-7)

3.8.13 Information Provided by HWT for Proposal 8

HWT provided a detailed technical description of the STATCOM, consisting of two independent ±281 MVAr units. HWT indicated that one STATCOM would be connected to the north end of the Round Mountain Substation 230 kV bus and one to the south end of the Table Mountain Substation 230 kV bus. HWT indicated that at Round Mountain Substation a second 500/230 kV transformer would be added and the 230 kV bus extended to accommodate this new transformer, the connection of HWT's STATCOM, and the expansion of the 500 kV ring bus to a full three-bay BAAH configuration, all by PG&E. HWT indicated that at Table Mountain Substation a second 500/230 kV transformer would be added and the 230 kV bus extended to accommodate this new transformer, the connection of HWT's STATCOM, and the addition of a circuit breaker to the center bay for the new transformer, all by PG&E. HWT indicated that it would provide blast walls and a solid perimeter wall at the STATCOM. (S-6, S-11) HWT indicated that the point of demarcation would be a bus coupling at the PG&E substation property line. (S-1)

HWT provided the same information regarding the engineering and design experience of it and its team for its proposal 8 as it did for its proposal 1. See the information set forth in Section 3.8.8 regarding this aspect of HWT's proposal for its engineering qualifications and experience for its proposal 8.

HWT provided a design criteria and detailed list of design standards and codes for the STATCOM. (S-6, S-7)

3.8.14 Information Provided by LSPGC

LSPGC provided a detailed description of the project design, which includes the installation of a six-position BAAH 500 kV switchyard that interconnects two independent ±264.5 MVAr, 500 kV STATCOM blocks on LSPGC's proposed site. LSPGC indicated that it would provide for a future addition of two BAAH bays. LSPGC indicated it would provide a blast wall (S-6). LSPGC indicated that if it were to be selected as the approved project sponsor, it would perform a risk assessment to determine the criticality of the new switchyard. LSPGC indicated that if North American Electric Reliability Corporation (NERC) reliability standard CIP-014 and the associated study determines it necessary, LSPGC would install a 10-12 foot solid wall around the substation. (S-11) LSPGC indicated that communications to support the primary protection schemes would use existing power line carrier signals on one of the existing 500 kV transmission lines to both Round Mountain Substation and Table Mountain Substation and that the secondary path would use the second 500 kV transmission line. (S-1, S-9)

LSPGC indicated that it or its primary engineering firm has completed the engineering and design of numerous overhead transmission line, substations, and dynamic reactive support projects, including projects in California. (P-1, S-2, S-3) LSPGC provided information on the firm that it has proposed to perform the design, procurement, and construction of the STATCOM and the firm that would serve as the owner's engineer. LSPGC provided a list of projects for which its proposed STATCOM design and construction firm has provided similar services, none in the United States, and indicated that three of them were 400 MVAR. (S-2, S-3) LSPGC identified several potential subcontractors that have engineering or design experience in the United States and California. LSPGC indicated that it has previously used its proposed STATCOM design and construction firm as a vendor. LSPGC indicated that it has worked with its proposed engineering firm on 500 kV transmission line projects. LSPGC provided its proposed engineering firm's experience with flexible alternating current transmission system (FACTS) engineering. (P-4, S-2, S-4)

LSPGC provided a design criteria for the project and provided a list of standards and requirements for the design of the STATCOM. (S-7)

3.8.15 Information Provided by SEGG for Proposal 1

SEGG provided a detailed description of the STATCOM, consisting of two independent +/-250 MVAr STATCOM units with a three phase 500 kV transformer, two voltage source converter units with a rating of +/- 135.6 MVAr connected to the 43 kV bus, and two sets of single phase reactors connected in series with each voltage source converter delta circuit at the 45.2 kV bus. SEGG indicated that there would be a spare transformer for the two independent STATCOM blocks. SEGG indicated that its substation would consist of three BAAH bays to connect the PG&E 500 kV transmission lines and STATCOM and would provide two future BAAH bays. SEGG indicated that it would provide blast walls and a solid perimeter wall (S-6, S-11) and that it would install Power Line Carrier on all four lines at the substation. (S-9)

SEGG provided an extensive list of projects for which it and its team have been responsible for designing, including reactive support projects constructed in California. (P-1, S-3) SEGG indicated that it has one ongoing project located in both Arizona and California, scheduled to be completed in 2021, which includes transmission line, substation, and reactive elements.

SEGG indicated that it plans to contract with one firm for STATCOM design and two other firms for the design and construction of the STATCOM substation and 500 kV overhead transmission circuits, and it provided a list of projects for which the firms have provided engineering, design, and construction services. The list included projects in California for one of the two firms providing design services. (S-2, S-3, T-2, T-3)

SEGG indicated that it is working with all of the firms that are working on the Delaney-Colorado River project, which is currently under development. (S-4, T-4)

SEGG provided a design criteria for the project and provided a list of standards and requirements for the design of the STATCOM and the 500 kV transmission lines. (S-7, T-7)

SEGG provided a list of substation standards that would be used on this project. (S-6, S-7)

3.8.16 Information Provided by SEGG for Proposal 2

SEGG provided a detailed description of the two independent +/-250 MVAr SVC units. SEGG indicated that the rating of each SVC block would be achieved by utilizing one 180 MVAr thyristor switched capacitor branch, one 320 MVAr thyristor controlled reactor branch, and one 70 MVAr harmonic filter tuned for the fifth harmonic. SEGG indicated that each unit would have a 500/27.5 kV three phase 250 MVA transformer. SEGG indicated that there would be a spare transformer for the two SVC blocks. SEGG indicated that its substation would consist of three BAAH bays to connect the PG&E 500 kV transmission lines and SVC and would provide two future BAAH bays. SEGG provided information for typical structure types, materials, and bus and breaker arrangement. SEGG indicated that it would provide blast walls and a solid perimeter wall. (Section 3, QP-1, QP-2, S-6, S-11) SEGG indicated that it would install Power Line Carrier on all four lines connected at the substation. (S-9)

SEGG provided an extensive list of projects for which it and its team have been responsible for designing, including reactive support projects constructed in California. (P-1, S-3) SEGG indicated that it has one ongoing project located in both Arizona and California, scheduled to be completed in 2021, which includes transmission line, substation, and reactive elements.

SEGG indicated that it plans to contract with one firm for SVC design and two other firms for the design and construction of the SVC substation and 500 kV overhead transmission circuits, and it provided a list of projects for which the firms have provided engineering, design, and construction services. The list included projects in California for one of the two firms providing design services. (S-2, S-3, T-2, T-3)

SEGG indicated that it is working with all of the firms that are working on the Delaney-Colorado River project, which is currently under development. (S-4, T-4)

SEGG provided a design criteria for the project and provided a list of standards and requirements for the design of the SVC and the 500 kV transmission lines. (S-7, T-7)

SEGG provided a list of substation standards that would be used on this project. (S-6, S-7)

3.8.17 <u>Information Provided by SPT1</u>

SPT1 provided a detailed description of the STATCOM, consisting of two independent +/- 250 MVAr independent STATCOM blocks that are stepped up from 46 kV to 500 kV, and a substation with three breaker-and-one-half (BAAH) bays to terminate the Round Mountain-Table Mountain 500 kV transmission lines. SPT1 indicated that room adjacent to the 500 kV substation would be provided for two future BAAH bays. SPT1 indicated that it would provide blast walls and a solid perimeter wall. (S-6, S-11) SPT1 indicated that it proposes to utilize Power Line Carrier for relay communications between this new BAAH 500 kV switchyard and PG&E's Round Mountain and Table Mountain Substations. (S-9)

SPT1 provided information on projects for which it or its team have completed the engineering or design or are ongoing, including three transmission line projects, 14 substation projects, and 21 substation or reactive support projects for its primary equipment manufacturer and EPC firm, some of which were located in California. (P-1) SPT1 indicated that it has a contract with its equipment manufacturer for total turnkey EPC services for both the STATCOM and switchyard. SPT1 provided a list of personnel for SPC, its equipment manufacturer and EPC firm, and its architectural engineering firm. (S-2) SPT1 indicated that its team has been involved with the engineering or design of six STATCOMs, SVCs, or synchronous condensers in the last five years, none in California, and that they own, operate, and maintain three STATCOMs and one synchronous condenser. (S-3)

SPT1 indicated that the project design would adhere to relevant IEEE and ANSI standards, as well as state specific requirements. (S-6, S-7)

3.8.18 Information Provided by Tenaska

Tenaska provided a detailed description of the STATCOM, consisting of two independent +/-250 MVAr STATCOM blocks, and a substation with three breaker-and-one-half (BAAH) bays to terminate the Round Mountain-Table Mountain 500 kV transmission lines. Tenaska indicated that room would be provided for two future BAAH bays. Tenaska indicated that it would provide blast walls and a solid perimeter wall. (S-6, S-11) Tenaska indicated that communication methods for supervisory control and data acquisition (SCADA) and protections schemes would be finalized with PG&E and implemented as part of the project sponsor's design and scope of supply. (S-9)

Tenaska provided an extensive list of transmission line, substation and reactive support projects for which it or its team have completed the engineering or design, including many in California. (P-1, S-3) Tenaska indicated that it would contract with a primary EPC contractor and identified two other equivalent reputable EPC organizations for design, procurement, construction, and startup of the 500 kV switchyard. Tenaska indicated that it would contract with a primary equipment manufacturer and identified two other equivalent equipment manufacturers for the STATCOM and identified a primary owner's engineering firm that is providing consulting services. Tenaska indicated that its engineering and construction team would oversee EPC firms, the equipment manufacturer, and primary owner's engineering firm and provided a list of key personnel. (P-1, S-3, S-4)

Tenaska provided a design criteria for the project and indicated that both 500 kV switching station and STATCOM design would adhere to all relevant IEEE, ANSI, and Western Electricity Coordinating Council (WECC) standards, California state-specific requirements, and applicable NERC reliability standards. (S-6, S-7)

3.8.19 Information Provided by TransCanyon

TransCanyon provided a detailed technical description of the STATCOM, consisting of two independent blocks with a total of +/- 500 MVAr multi modular converter voltage source converter, (S-7) and a substation with three breaker-and-one-half (BAAH) bays to terminate the Round Mountain-Table Mountain 500 kV transmission lines. TransCanyon indicated that room would be provided for two future BAAH bays. TransCanyon indicated that it would provide blast walls and a solid perimeter wall. (S-6, S-11) TransCanyon indicated that the 500 kV transmission line differential protection would communicate with the PG&E equipment interface at PG&E's Round Mountain Substation and PG&E's Table Mountain Substation through two separate, redundant microwave paths.

TransCanyon provided a list of transmission line, substation, and reactive support device projects, including a STATCOM, for which PNW and BHE, through their subsidiaries, have provided the engineering or design services that did not include projects in California. (P-1) TransCanyon identified its proposed EPC contractor, another firm for the design and construction of the STATCOM, and a third firm for construction services for the substation and transmission line. TransCanyon provided a list of projects for which the firms have provided the engineering or design services, and all have completed projects in the United States. TransCanyon's list indicated that the proposed EPC contractor has completed projects in California. (S-2, S-3, S-4, T-2, T-3, T-4)

TransCanyon provided a detailed design criteria and indicated that the STATCOM would consist of a single multi-modular converter voltage source converter. TransCanyon provided a list of substation standards that would be used on this project. (S-6, S-7)

3.8.20 <u>ISO Comparative Analysis</u>

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, the process that must be followed in California to comply with the California Environmental Quality Act 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 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 six project sponsors' teams have experience permitting projects in the U.S. and in California, including experience with the environmental permitting process for substations 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 contractors 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. Based on the permitting experience of the project sponsors and their teams, 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 HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, SPT1, Tenaska, and TransCanyon with regard to environmental permitting experience, including experience in California. All of the project sponsors have capable teams regarding environmental permitting that are qualified to perform the activities necessary to obtain all environmental permits.

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, substation, and reactive support device 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, substation, and reactive support device project engineering and design experience in other countries because 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, substations, and reactive support devices in California includes adherence to requirements of the California Building Standards Commission, the California Energy Commission, the California Environmental Protection Agency, the California Occupational Safety and Health Administration (Cal-OSHA), California High Voltage Electrical Safety Orders, California Building Code Title 24, and county and city planning and permitting requirements.

HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon, including their teams, have extensive experience with overseeing the engineering and design of transmission lines, substations, and reactive support devices. The affiliates and firms identified in the twelve proposals of the six project sponsors as responsible for the engineering and design of the project have transmission line and substation engineering and design experience in the U.S. and California.

HWT, LSPGC, SEGG, SPT1, Tenaska, and TransCanyon affiliates and designated design firms have completed the engineering and design of substation projects, including reactive support device projects, in both the U.S. and California.

All of the project sponsors have previous experience with their designated design firms.

Regarding its analysis of this component of the factor, the ISO considers the engineering and design firms identified by the project sponsors as part of their teams to be highly qualified. 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 there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon with regard to 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 HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon for either the first component or the second component of this factor.

As a result, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon regarding this factor overall. The ISO notes again that all of the project sponsors and their teams are qualified and fully capable of handling the engineering and permitting work associated with this project.

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

(Section 3 - General Project Information , QS-1, QS-4, P-1, P-2, P-6, P-7, E-14a, E-14b, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-2, S-3, S-4, T-2, T-3, T-4)

3.9.1 <u>Information Provided by HWT for Proposals 1, 2, 3, 6, 7, and 8</u>

HWT provided an extensive list of transmission line, substation, and reactive support device projects, including projects in California, that it or its team have constructed. (P-1, S-3, S-4, T-4) HWT indicated that the list of projects demonstrates HWT's ability to construct the project and demonstrates its knowledge of California requirements. HWT indicated that NextEra has previous experience with all of the firms that HWT identified as potential construction contractors. (S-3, S-4)

3.9.2 <u>Information Provided by LSPGC</u>

LSPGC provided an extensive list of transmission line, substation, and reactive support device projects constructed by its four proposed construction contractors and selected STATCOM EPC partner including projects in California LSPGC indicated that it has used its proposed STATCOM design and construction firm previously to supply 345 kV variable reactors and step-up transformers on multiple generation projects. (S-2, S-3, S-4) LSPGC provided a list of projects for its proposed owner's engineer that have been completed or are in progress. (S-4, T-4) LSPGC indicated that its proposed owner's engineer provided design services for the Harry Allen–Eldorado 500 kV project in Nevada. (T-4)

3.9.3 Information Provided by SEGG for Proposals 1 and 2

SEGG identified the Delaney-Colorado River 500 kV transmission line project with series compensation located in Arizona and California for which it is responsible for construction. (P-1, S-4, T-4) SEGG identified potential engineering firms, construction firms, and suppliers of major equipment for the project. (S-3, T-3) SEGG provided a list of its proposed STATCOM, SVC, and series compensation vendor's projects for proposals 1 and 2, respectively, which included installations in the U.S and three series compensation projects in California. (P-1, S-3) SEGG indicated that its EPC contractor and construction contractor have completed a total of six transmission line projects and 15 substation projects within the U.S., many in California. (P-1, S-3, T-3) SEGG indicated that it is using its engineering firm, EPC and construction firm, and its STATCOM and SVC vendor for the Delaney-Colorado River 500 kV transmission line project. (P-1, S-4)

3.9.4 Information Provided by SPT1

SPT1 provided information on projects that it or its team have constructed or are ongoing, including three transmission projects, none in California, three substation projects, none located in California, and 11 substation or reactive support projects for its proposed primary equipment manufacturer and EPC firm, none located in California, and indicated it would contract with its primary equipment manufacturer and EPC firm for both the STATCOM and switchyard. (P-1, S-2) SPT1 indicated that Southern Company has been involved in 10 STATCOM, SVC, or synchronous condenser projects, none in California, and that SPC oversaw construction of and owns, operates, and maintains three STATCOMs and one synchronous condenser and that SPC employees involved with this project have been involved in aspects of the three SPC reactive support devices, including design, construction, integration, operating, and maintaining those facilities. SPT1 identified two SVC projects completed with its primary EPC firm and six projects where its primary architectural engineering firm has provided service in California. (S-3, S-4) SPT1 indicated that the projects it identified demonstrate its ability to construct this project and its knowledge of California requirements. (QS-4)

3.9.5 Information Provided by Tenaska

Tenaska provided a list of transmission line, substation, and reactive support projects that it or its team have constructed or are ongoing, including one transmission line and seven substation projects, all in California, and provided a list of projects constructed by its primary EPC contractor and other EPC firms. (P-1) Tenaska indicated that this experience demonstrates its ability to construct this project and that its primary engineering firm and primary EPC firm have knowledge of California requirements. (S-6, S-7)

3.9.6 Information Provided by TransCanyon

TransCanyon provided a list of transmission line, substation, and reactive support projects that it and its team have constructed, including six projects with its proposed

EPC contractor, and indicated that a 500/345/230 kV transmission line that includes a STATCOM substation component, is in the construction phase. (S-3, S-4) TransCanyon also indicated that it has retained an EPC contractor and construction contractor with extensive experience in California. (Introduction, P-1)

TransCanyon indicated that its delivery team (led by personnel from PacifiCorp, a TransCanyon affiliate), has commenced construction of PacifiCorp's Latham STATCOM project, to be delivered on a turnkey basis, scheduled to go into service in October 2020. (Letter of Transmittal)

Maintenance Record

(Section 1 - Executive Summary, Section 3 - General Project Information, QS-1, QS-4, P-1, O-1, O-3, O-4, O-5, O-6, O-9, O-11, O-14, O-18, O-19)

3.9.7 Information Provided by HWT for Proposals 1, 2, 3, 6, 7, and 8

HWT indicated that NextEra owns approximately 8,700 circuit miles of high-voltage transmission and 830 substations across North America, including California. (Section 3, O-3)

HWT indicated that NEET recently completed its acquisition of Trans Bay Cable, LLC (TBC), which further increases its presence, experience, and capabilities in California. HWT indicated that TBC operates a submarine high voltage direct current (HVDC) transmission system that utilizes similar technology to this project. (Section 3, O-1)

HWT indicated that its affiliates have significant experience maintaining a wide range of substation, transmission, and related infrastructure throughout North America, including extra high-voltage (EHV) lines and dynamic reactive support equipment. (Section 3) HWT indicated that its O&M staff's capabilities are confirmed by consistently low transmission outage rates. HWT indicated that FPL, for example, achieved top-decile transmission reliability performance in a recent benchmarking study. (Section 3, QS-1, QS-4)

HWT indicated that it plans to operate and maintain the project through agreements with its experienced affiliates with support from equipment manufacturers and specialty contractors. In particular, HWT indicated that it plans to utilize NextEra's existing pool of high-voltage technicians and existing field support resources already located in California to support existing power generation and transmission assets. HWT indicated that these personnel would be responsible for providing 24/7 on-call response, site switching and safety, routine inspection and maintenance, and general site care duties. (Section 3)

HWT indicated that it may also utilize equipment manufacturers and contractors to support operations and maintenance. (Section 3)

HWT indicated that it has an existing corporate service agreement with NEER for operating services that are provided by NEER Operating Services, LLC (OSI). HWT indicated that OSI provides O&M services for NEER as well as third party generation owners. HWT indicated that the OSI field operations team that would support the project is responsible for O&M on approximately 205 substations and 1,190 circuit miles of lines, up to 500 kV. (QS-1, QS-4)

HWT indicated that it and its affiliates have experience with owning, operating, and maintaining dynamic reactive support devices and its associated control systems with more than 500 MVAr of SVC, 360 MVAr of synchronous condensers, 8,000 MVAr of transmission level manually switched capacitors, and 3,000 MVAr of series compensation. HWT indicated that, in addition, it would be able to leverage TBC operations and maintenance staff who operate and maintain the two TBC converter stations, which each have a STATCOM capability of a maximum reactive power of +/- 300 MVAr at zero MW. HWT indicated that the total power transformer capability operated and maintained by HWT affiliates is more than 160,000 MVA, of which 140,000 MVA is subject to NERC jurisdiction. (QS-1, QS-4, O-6)

HWT stated that it has experience owning, operating, and maintaining 130 MVAr of STATCOM. (QS-1)

HWT indicated that it has access to more than 700 in-house power system professionals, including technicians and other staff with expertise in all aspects of transmission and substation equipment installation, maintenance, and repair. (QS-1, QS-4, O-6)

HWT listed many transmission line and substation projects for which NextEra or its affiliates have O&M responsibility. HWT also provided a list of projects in California, Florida, and Texas for which NextEra has O&M responsibility, including several with dynamic reactive support components. HWT indicated that with the acquisition of TBC, NextEra has now added to its affiliates' expertise for the operation and maintenance of its 53-mile +/- 200 kV, 400 MW, HVDC system. (P-1, O-3)

HWT indicated that the existing NextEra O&M organization has a program of maintenance standards providing the capability to manage compliance to the provisions of the Transmission Control Agreement (TCA) among the ISO and the PTOs, and the ISO's transmission maintenance standards. (O-6)

HWT indicated that this capability is supported by NextEra O&M team members' experience with the TCA requirements and ISO's transmission maintenance standards. HWT indicated that one of its team members was a past voting member of the ISO's Transmission Maintenance Coordinating Committee and participated in the continuous development of maintenance procedures to support the ISO's transmission standards. (O-6)

HWT indicated that NextEra has well-established practices and procedures for transmission system operations and maintenance of its transmission and substation facilities, which are derived from FPL's O&M practices for its facilities. HWT indicated that its O&M team members have experience maintaining SVCs, STATCOMs, capacitors, series compensators and synchronous condensers. This includes integrating the operations of new FACTS assets into the ISO system: Suncrest SVC and TBC HVDC STATCOM. (O-6)

HWT indicated that TBC is an existing PTO working in accordance with the TCA and that TBC has operated its facilities under the operational control of the ISO for almost 10 years. HWT indicated that its emergency support vendor has energy storage and FACTS device experience. (O-6, O-18, O-19)

HWT indicated that it will utilize NextEra's procedures and processes in capturing and reporting annual availability and indicated that they align with the current reporting obligations stated in the TCA. HWT provided a list of performance metrics collected by NextEra and the 2018 annual performance filed with the Florida Public Service Commission. (O-9)

3.9.8 Information Provided by LSPGC

LSPGC indicated that it would perform maintenance activities with internal staff supported by key contractors, including its proposed STATCOM design and construction firm, its primary emergency response and maintenance contractor, and its backup emergency response and maintenance contractor. LSPGC indicated that its operating and maintaining experience includes over 300 miles of EHV transmission lines, four EHV substations, and associated facilities using the same organizational structure and key personnel as planned for the project. (O-1, O-3)

LSPGC indicated that it intends to contract with its proposed STATCOM design and construction firm to conduct preventative and predictive maintenance, perform emergency repairs, and complete major facility rebuilds for the STATCOM facility. (O-1, QS-4)

LSPGC indicated that it has entered into emergency response and field services agreements with two companies for emergency response, restoration services and maintenance. LSPGC indicated that its primary emergency response and maintenance contractor has offices in California and elsewhere in the west and has an extensive combined fleet of specialized electrical construction services equipment and a large, collective workforce of qualified personnel. LSPGC indicated that its primary emergency response and maintenance contractor would support the project from its northern California office and would have the resources of the entire organization available to it. LSPGC indicated that the company has a long history of providing services to substation, transmission and distribution clients. (Section 1, Section 3, QS-1, QS-4)

LSPGC indicated that the secondary emergency response and maintenance contractor for the project has staff and equipment located in northern, central, and southern California. LSPGC indicated that the secondary emergency response and maintenance contractor provides electrical construction services throughout the United States and Canada. LSPGC indicated that it has thousands of employees and one of the nation's largest fleets of specialized transmission, substation, and distribution equipment. LSPGC also indicated that its secondary emergency response and maintenance contractor has an extensive history of providing services to clients through long-term maintenance contracts and has worked with LSPGC on a number of projects. (Section 1, Section 3, QS-1, QS-4, O-1)

LSPGC indicated that it currently has five staff in its transmission maintenance group with an average experience of over 15 years, one additional field employee would be added in 2019, one additional substation technician dedicated to the project and based in California near the project location would also be added to support maintenance of the project, and one electrical engineer located in northern California would also be available to support the project. (QS-4, O-1, O-3)

LSPGC indicated that it has been operating and maintaining four EHV substations and associated facilities over the past five years using the same organizational structure and key personnel as planned for the project. (O-3)

LSPGC indicated that it has not had any unscheduled outages since the energization of its transmission systems, with the exception of storm damage. LSPGC indicated that it submits Transmission Availability Data System reports to NERC and included a table of availability of its transmission line assets for the last five years. (O-9)

3.9.9 Information Provided by SEGG for Proposals 1 and 2

SEGG indicated that it would enter into a comprehensive O&M services agreement with a service provider to perform O&M services and NERC compliance for the project. (Section 3)

SEGG indicated that its proposed O&M services provider has many years of experience and has thousands of employees, in more than 150 offices and facility sites. SEGG indicated that its O&M services provider serves public and private utilities, independent power producers, industrials, and financial investors. SEGG indicated that Starwood Energy has significant experience in outsourcing and overseeing the performance of O&M services and that the outsourcing approach allows Starwood Energy to secure the best and customized O&M service providers for each asset. (QS-4)

SEGG provided information on two transmission line projects outside of California where it has direct experience, through an O&M services agreement, with project maintenance in the last five years. (P-1, O-3)

SEGG indicated that, within the last five years, its proposed O&M services provider has been involved with the operations and maintenance of eleven recently-constructed transmission line projects, of which it has provided maintenance services for six projects. SEGG indicated that, within the last five years, its O&M services provider has been involved with the operation and maintenance of four recent substation projects, including reactive support and series compensation projects, of which it has provided maintenance services for three projects. (P-1)

SEGG indicated that its O&M services provider's agreements typically have key performance indicators that are useful in assessing actual performance against targets in technical performance and commercial performance. (O-9)

3.9.10 Information Provided by SPT1

SPT1 indicated that SCS would support SPC, which would provide engineering and construction support for SPT1, and would be responsible for post-construction monitoring of project operations and maintenance. SPT1 indicated that SPC, SCS, or an approved third party would be responsible for project operations and taking actions at the direction of the ISO. (Section 3)

SPT1 indicated that SPC and SCS have affiliates that own, operate, and maintain extensive generation and transmission facilities across the United States, including more than 18,000 miles of high voltage transmission lines and more than 1,100 high voltage transmission substations. SPT1 indicated that SCS provides services on behalf of these affiliated companies, including transmission-related operations and maintenance activities and operation of the Southern Company systems. SPT1 indicated that SPC has extensive experience developing, constructing, owning, operating, and maintaining facilities in the state of California as well. (QS-4)

SPT1 indicated that it would utilize its proposed STATCOM equipment manufacturer for turnkey EPC services and maintenance, pursuant to a fixed-price EPC contract. SPT1 indicated that its proposed STATCOM equipment manufacturer is currently responsible for serving the North American power systems and rail transportation with electrical and electronic products, systems, and services. (Section 3)

SPT1 indicated that Southern Company has been involved in various aspects of ten STATCOM, SVC, or synchronous condenser projects over the past several years. SPT1 indicated that the SCS operations and compliance teams have been involved with each of the ten projects. SPT1 indicated that SPC employees have all been involved in some aspects of the three SPC reactive support devices, including design, construction, integration, operating, and maintaining these facilities. (QS-4, S-3, S-4)

SPT1 indicated that its proposed STATCOM equipment manufacturer is currently contracted to perform service on approximately 15 of its SVC and STATCOM facilities installed throughout North America. SPT1 indicated that its proposed STATCOM equipment manufacturer has on staff factory-trained field technicians who can perform routine maintenance on STATCOM valves, cooling, and controls. SPT1 indicated that its proposed STATCOM equipment manufacturer also has the capability to incorporate other substation maintenance specialties (*e.g.*, protective relaying, instrument transformers, and circuit breakers) into its maintenance service offerings. (P-1, O-3)

SPT1 indicated that Southern Company follows a three-step process of screening and testing to ensure only appropriately qualified, skilled, and experienced persons are hired to perform maintenance and construction for substation work. (O-4)

SPT1 indicated that lineman and substation personnel typically have over 2,000 hours of training a year and this includes both classroom and field training. SPT1 indicated that classroom training includes learning the basics of the entire electrical system from generation through transmission, distribution, the meter, and electrical safety and tools. SPT1 indicated that field testing includes theory and application of pole climbing, pole and major substation inspections, personal protective equipment, and fall protection. SPT1 indicated that lineman and substation personnel are required annually to take written test as well as classroom and field training to maintain their qualifications for construction, maintenance, and operation of Southern Company electrical systems. (O-5)

SPT1 indicated that SPC has a consistent strong record of delivering on its key operating performance metrics, illustrating its commitment to operational excellence and ensuring SPS meets contractual commitments its customers. (O-9)

3.9.11 Information Provided by Tenaska

Tenaska indicated that it has begun discussions with potential third-party suppliers and contract providers, including a leading operations and maintenance company. Tenaska indicated that it has not chosen contractors to manage the execution, the construction, and the O&M of the project. Tenaska indicated that these third-party contractors would be managed by the project company, which would draw on the resources of its corporate affiliates at Tenaska. (Section 3, QS-1)

Tenaska indicated that it currently manages and operates nearly 8,000 MW of power generation and associated interconnection equipment. Tenaska indicated that for transmission-specific operations needs, it intends to contract with an experienced third party. (QS-4)

Tenaska provided information regarding two transmission line projects (above 200 kV) and three substation projects for which it has direct experience with project maintenance in the last 5 years. Tenaska provided information on two STATCOM or SVC projects maintained by its proposed equipment manufacturer from the last five years over 200 kV. (P-1)

Tenaska indicated that for most of its fleet of generation facilities, it directly provides comprehensive operations and maintenance services through its subsidiary, Tenaska Operations, Inc. Tenaska indicated that it has multiple transmission or substation facilities associated with its fleet of generation facilities. Tenaska indicated that these systems range in voltage from 230 kV to 500 kV. Tenaska indicated that it had prior experience with a facility rated at 750 kV, which is no longer owned by Tenaska. Tenaska indicated that it also owns several 34.5 kV capacitor banks that are used for system voltage support in the ISO area. (O-3)

Tenaska indicated that it has more than a 30-year track record of attracting and hiring talented, qualified personnel for its fleet of generation facilities across the nation. Tenaska indicated that the new hire process includes rigorous formal training and qualification programs. Tenaska indicated that because its proposed O&M service provider is expected to provide O&M staffing for this project, it provided information based on its O&M service provider's training and qualification programs.

Tenaska indicated that its proposed O&M service provider hires field personnel with transmission, WECC power grid, and substation technical and leadership experience with a work history that demonstrates a pattern of accomplishments and advancement. Tenaska indicated that for its O&M service provider's field personnel a Bachelor of Science degree in electrical engineering or equivalent is desired. (O-4)

Tenaska provided a description of the its proposed O&M service provider's training program, including the following lineman and electrician certification requirements:

- Each lineman is required to complete a 3-4 year apprenticeship program, the OSHA transmission and distribution 10-hour and 20-hour training programs, and training in first aid, CPR, bucket rescue, pole top rescue, grounding, and rigging.
- Substation electricians are required to undertake the same training as lineman and also have specialty training for the various equipment on which they are required to be working. (O-5)

Tenaska indicated that as part of its 30-year history operating power generation facilities, it participated in the NERC Generating Availability Data System, as did its proposed O&M service provider.

Tenaska indicated that its proposed O&M service provider performs Generation Availability Data System and Transmission Availability Data System reporting across its fleet of generation and transmission facilities, as required by NERC. Tenaska indicated that its O&M service provider is currently supporting reporting for more than 170 facilities.

Tenaska indicated that its proposed O&M service provider's agreements typically have key performance indicators that are useful in assessing actual performance against targets in technical and commercial areas. Tenaska indicated that the key performance indicators promote alignment of interests and working together for the common good.

Tenaska indicated that its proposed O&M service provider has executed more than 300 operations and maintenance agreements during is history. (O-9)

Tenaska indicated that it and its proposed O&M service provider both have decades of O&M experience for large scale generating facilities across the nation. (O-18)

3.9.12 Information Provided by TransCanyon

TransCanyon indicated that it has signed an MOU with PacifiCorp to provide operations support and to facilitate maintenance services for the project. TransCanyon indicated that in order for PacifiCorp to offer the services to TransCanyon, both PacifiCorp and TransCanyon must obtain exemptions from certain affiliate transaction rules of the CPUC and may be required to comply with other requirements of applicable jurisdictions restricting or requiring notice of transactions between affiliates necessary for PacifiCorp to perform, and TransCanyon to receive, the services. TransCanyon indicated that if PacifiCorp and TransCanyon achieve affiliate transaction rule compliance, PacifiCorp may choose, subject to any necessary additional regulatory filings and the receipt of additional regulatory approvals, to offer the services to TransCanyon. TransCanyon indicated that it believes that the above regulatory approvals can be obtained in the ordinary course similar to how NextEra obtained approval in the Suncrest SVC project CPUC proceeding (A.15-08-027). (Section 3, O-1)

TransCanyon indicated that its maintenance lead would be a PacifiCorp employee with over 20 years of experience and expertise. TransCanyon indicated that by using PacifiCorp to provide operations and facilitate maintenance services, TransCanyon would have the advantage of integrating the operations of the project into PacifiCorp's existing infrastructure and that this capability would be even more valuable considering the fact that PacifiCorp is on-track for placing a STATCOM in service this year at its Latham Substation in Wyoming. TransCanyon indicated that the same team that would support the Latham Substation facility with compliance policies, systems, and highly trained, qualified staff would be in place and would be able to directly apply expertise from the Latham Substation facility for the benefit of the project. (Section 3, QS-1, QS-4)

TransCanyon indicated that it has agreed in principle to a maintenance service agreement with its proposed STATCOM manufacturer for preventative maintenance services and executed a maintenance service agreement with its proposed construction contractor for inspection and emergency response. (O-1)

TransCanyon indicated that its team is primarily composed of team members from affiliates of its two parent companies, PNW and BHE. TransCanyon indicated that PNW, through its subsidiary APS, has built electric infrastructure since 1886 and continues maintain and own a broad range of transmission infrastructure projects and other energy assets in Arizona. TransCanyon indicated that APS Transmission Operations and Transmission Maintenance are responsible for the operation and maintenance of 24 500 kV transmission lines totaling 1,456 miles, six 345 kV transmission lines totaling 578 miles, 45 230 kV transmission lines totaling 794 miles, and five 115/161 kV transmission lines totaling 159 miles, including the EHV elements in WECC-rated paths. TransCanyon indicated that subsidiaries and affiliates of BHE have built and continue to maintain and own a broad range of transmission infrastructure projects and other energy assets in several states, including California. TransCanyon indicated that BHE, through its subsidiaries, currently owns, operates and maintains approximately 33,000 miles of transmission lines. (P-1)

TransCanyon listed eight projects completed within the last five years, three of which included reactive support facilities, for which it, and its affiliates, have maintenance responsibility. (P-1)

TransCanyon indicated that PacifiCorp has extensive experience operating and maintaining a large and complex transmission system. TransCanyon indicated that the company serves six states and has operated EHV transmission lines since the early 1970s. TransCanyon indicated that PacifiCorp is responsible for the operation and maintenance of eight 500 kV transmission lines totaling 1,211 miles, 60 345 kV transmission lines totaling 3,145 miles, 154 230 kV transmission lines totaling 3,496 miles, and 600+ 115/161-kV transmission lines totaling 4,465 miles. (O-1, O-3)

TransCanyon indicated that its maintenance service provider is well-positioned as a suitable contractor for performing maintenance and emergency response support for the project because it has a local California presence as well as subsidiaries that can provide management, manpower, material, and fleet resources that are conveniently located throughout California, providing accessibility throughout the region. TransCanyon indicated that its maintenance service provider holds maintenance agreements with five utility clients throughout the western United States, including one in California. TransCanyon indicated that its maintenance service provider has been providing services to its affiliates PacifiCorp and APS since 1995 and 2017, respectively. (O-3)

TransCanyon indicated that its STATCOM manufacturer meets its customers' maintenance needs via a complete life-cycle care agreement. TransCanyon indicated that the agreement represents production availability insurance for FACTS installations, providing the most cost-effective solution to maximize production up-time, availability and reliability. (O-3)

TransCanyon indicated that through its affiliated operating companies it is familiar with control chart methodology described in the TCA. TransCanyon indicated that APS has monitored availability performance of its 500 kV and 345 kV transmission lines using this process for over 10 years. (O-9) TransCanyon provided a sample of this analysis from APS. (O-9)

TransCanyon indicated that APS and PacifiCorp use other methodologies including forced outage per 100-mile year, NERC Transmission Availability Data Systems, and Average Service Availability Index that are also employed in the industry. TransCanyon indicated that APS has the capability of capturing all the necessary data to compute availability performance based on the methodology described in the TCA. (O-9)

TransCanyon provided a figure showing the past ten years of data for PacifiCorp transmission availability. (O-9)

3.9.13 ISO Comparative Analysis

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 projects, including substations and reactive support devices, 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, reactive support device, and substation construction experience in other jurisdictions because 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, U.S. laws, rules, regulations, and processes applicable to construction of transmission lines, reactive support devices, and substations include federal OSHA, National Environmental Policy Act, Storm Water Pollution Prevention Plan, and U.S. Fish and Wildlife Service requirements, Fair Labor Standards Act regulations, and National Electric Code standards. Also, transmission line and substation projects developed in the U.S. and California must adhere to the National Electrical Safety Code published by the Institute of Electrical and Electronics Engineers (IEEE). In addition, in California the process that must be followed for the construction of transmission lines, reactive support devices, and substations 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. All of the project sponsors provided information on the California-specific rules, regulations, and laws that might affect the construction of transmission lines, reactive support devices, and substations in California.

Regarding its analysis of this component of the factor, the ISO first points out that it considers the construction contractors identified by the project sponsors as part of their teams to be qualified and fully capable of handling the construction work associated with this project. As a result, the ISO's analysis identifies only the slightest of advantages for any project sponsor over any other with these construction firms on its team.

All project sponsors are using or considering experienced STATCOM manufacturers for the installation of the reactive support device. Although the number of transmission facilities constructed varies among the proposed project sponsors' teams, all six project sponsors teams have established experience in the construction of transmission line, reactive support device, and substation projects, including projects in California, and prior experience of the project sponsors working with their potential construction firms. TransCanyon also indicated that, in conjunction with its proposed STATCOM provider, the TransCanyon delivery team led by personnel from PacifiCorp, an affiliate of TransCanyon, is currently constructing a STATCOM in Wyoming, which is expected to be in-service in 2020. In addition, SPT1 indicated that SCS has been involved with ten STATCOMs, SVCs, or synchronous condensers over the past several years and that SPC employees have been involved in aspects of three SPC reactive support devices, including design, construction, integration, operating, and maintaining these facilities. However, its proposal showed less California experience than TransCanyon's proposal.

Based on the foregoing considerations, and considering the nature and scope of the construction involved with this project, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that TransCanyon's proposal is slightly better than SPT1's proposal, which is slightly better than the proposals of the other four project sponsors and there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, and Tenaska with regard to this component of the factor. The ISO notes that all of the project sponsors and their teams are qualified and capable of handling the construction work associated with this project.

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 considers all six of the project sponsors and their proposed teams to have the basic capability to manage the maintenance of the project for their twelve proposals. However, the information provided by the project sponsors regarding the amount of past experience with the maintenance of EHV transmission facilities and reactive support devices varied widely among the project sponsors and their proposed teams.

HWT, for its proposals 1, 2, 3, 6, 7, and 8, indicated a significant amount of experience with the maintenance of EHV transmission facilities, including reactive support devices, including 130 MVAr of STATCOM and including experience with the Trans Bay Cable project, which NEET has recently acquired. HWT's proposals also indicated experience dealing with the ISO and the maintenance requirements of the TCA.

SPT1 indicated that SCS has been involved with ten STATCOMs, SVCs, or synchronous condensers over the past several years and that SPC employees have been involved in aspects of three SPC reactive support devices, including design, construction, integration, operating, and maintaining these facilities. SPT1's proposal did not indicate any experience with the requirements of the TCA.

TransCanyon's proposal indicated a significant amount of experience with the maintenance of EHV transmission facilities, including reactive support devices, and demonstrated greater experience with the maintenance of EHV transmission facilities and reactive support devices than LSPGC, SEGG, for its proposals 1 and 2, and Tenaska but slightly less experience with reactive support equipment than SPT1 and no experience with the TCA. TransCanyon's proposal also indicated that although

TransCanyon's proposed team has relevant O&M experience, the team's affiliation with TransCanyon is subject to regulatory approvals.

LSPGC's proposal indicated that LSPGC has experience with EHV transmission facilities maintenance but more limited experience than HWT, SPT1, or TransCanyon, although more than that of SEGG, for its proposals 1 and 2, and Tenaska. LSPGC's proposal indicated that it has an existing team and established O&M processes that would be applied to the project and that its O&M contractors have a strong presence in California providing maintenance for transmission facilities.

The proposals of SEGG, for its proposals 1 and 2, and Tenaska indicated that their O&M contractors would be responsible for maintenance of the project and that their O&M contractors have less experience maintaining EHV transmission facilities subject to NERC compliance than the experience reflected in the proposals of the other project sponsors. Tenaska indicated that it had not yet contracted with its maintenance contractor.

Based on the specific information provided in the project sponsors' proposals, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, with regard to this component of the factor and that these proposals are slightly better than the proposals of the other five project sponsors regarding to this component. The ISO has also determined that SPT1's proposal is slightly better than TransCanyon's proposal, which is slightly better than LSPGC's proposal, which is slightly better than the proposals of SEGG, for its proposals 1 and 2, and Tenaska, between which there is no material difference, with regard to this component of the factor. The ISO notes that all of the project sponsors are qualified and capable of maintaining the transmission facilities associated with this project.

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.

With regard to the first component of this factor (previous record regarding construction of transmission facilities), the ISO has determined that TransCanyon's proposal is slightly better than SPT1's proposal, which is slightly better than the proposals of the other four project sponsors, and that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, and Tenaska with regard to this component.

With regard to the second component of this factor (the previous record regarding maintenance of transmission facilities), the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, and that they are slightly better than the proposals of the other five project sponsors and that SPT1's proposal is slightly better than TransCanyon's proposal, which is slightly better than LSPGC's proposal, which is slightly better than the proposals of SEGG, for its proposals 1 and 2, and Tenaska, among which there is no material difference, with regard to this component.

Based on the foregoing, and considering the slight differences among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, SPT1, and TransCanyon with regard to both of the foregoing components, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, SPT1, and TransCanyon and that they are slightly better than LSPGC's proposal, which is slightly better than the proposals of SEGG, for its proposals 1 and 2, and Tenaska, among which there is no material difference, with regard to 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

(Section 3 – General Project Information , QS-1, QS-4, P-1, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-5, S-7, T-6, C-1, C-2, C-3, C-4, C-5, C-6, C-7, C-8)

3.10.1 <u>Information Provided by HWT for Proposals 1, 2, 3, and 6</u>

HWT provided design details for the STATCOM. (S-7) HWT indicated that it would use a three-part approach to construction, provided an inspection process by HWT personnel, indicated that its contractors would develop quality assurance/quality control (QA/QC) plans, and indicated that the engineer of record would perform site visits, inspections, and walk downs. (C-1) HWT indicated that there would be one material yard for three contractors (C-2). HWT indicated that the project is being constructed in green field conditions and that clearances would not be required during construction, but clearances and outages would be required by PG&E for the purposes of looping the existing 500 kV circuits into the new switchyard. (C-3)

HWT provided a constructability review process, including a review with everyone involved with the project before mobilization. (C-4) HWT indicated that it would have responsibility for the overall project schedule. HWT provided a preliminary schedule and indicated that it would track the schedule with Primavera software, hold weekly meetings, and request a recovery plan when schedule variances are identified. (C-6). HWT indicated that it would develop an environmental compliance matrix with a list of all permitting requirements, conditions, and mitigation measures (C-5), that it does not anticipate any unique or special construction techniques (C-7), and that it and its affiliates have not had any notices of violation, fines, or law violations, nor are they under any investigations related to their transmission line and substation siting, permits, or rights-of-way and land acquisitions in the last five years. (C-8)

3.10.2 Information Provided by HWT for Proposal 7

HWT provided design details for the STATCOM. (S-7) HWT indicated that it would use a three-part approach to construction, provided an inspection process by HWT personnel, indicated that its contractors would develop QA/QC plans, and indicated that the engineer of record would perform site visits, inspections, and walk downs. (C-1) HWT indicated that there would be one material yard for three contractors at each site. (C-2) HWT indicated that it would construct two new 230 kV reactive support stations in green field locations adjacent to the existing Round Mountain and Table Mountain Substations with new underground transmission circuits connecting to the respective substation. HWT indicated that construction of the new reactive support substations would require special clearances and outages by PG&E (C-3) and that HWT underground circuits at Table Mountain would cross under PG&E's 500 kV and 230 kV circuits. (C-3)

HWT provided a constructability review process, including a review with everyone involved with the project before mobilization. (C-4) HWT indicated that it would have responsibility for the overall project schedule. HWT provided a preliminary schedule and indicated that it would track the schedule with Primavera software, hold weekly meetings, and request a recovery plan when schedule variances are identified. (C-6) HWT indicated that it would develop an environmental compliance matrix with a list of all permitting requirements, conditions, and mitigation measures (C-5), that it does not anticipate any unique or special construction techniques but would use horizontal directional drilling to install portions of the duct bank (T-1, C-7), and that it and its affiliates have not had any notices of violation, fines, or law violations, nor are they under any investigations related to their transmission line and substation siting, permits, or rights-of-way and land acquisitions in the last five years. (C-8)

3.10.3 Information Provided by HWT for Proposal 8

HWT provided design details for the STATCOM. (S-7) HWT indicated that it would use a three-part approach to construction, provided an inspection process by HWT personnel, indicated that its contractors would develop QA/QC plans, and indicated that the engineer of record would perform site visits, inspections, and walk downs. (C-1) HWT indicated that there would be one material yard for three contractors at each site. (C-2) HWT indicated that it would be constructing two new 230 kV reactive support stations on PG&E property at the existing Round Mountain and Table Mountain Substations and that construction of the new reactive support substations would require special clearances and outages by PG&E. HWT indicated that it has assumed that the newly constructed STATCOMs would be connected via bus extension to the existing Round Mountain and Table Mountain 230 kV busses. (C-3)

HWT provided a constructability review process, including a review with everyone involved with the project before mobilization. (C-4). HWT indicated that it would have responsibility for the overall project schedule. HWT provided a preliminary schedule and indicated that it would track the schedule with Primavera software, hold weekly meetings, and request a recovery plan when schedule variances are identified. (C-6) HWT indicated that it would develop an environmental compliance matrix with a list of all permitting requirements, conditions, and mitigation measures (C-5), that it does not anticipate any unique or special construction techniques (C-7), and that it and its affiliates have not had any notices of violation, fines, or law violations, nor are they under any investigations related to their transmission line and substation siting, permits, or rights-of-way and land acquisitions in the last five years. (C-8)

3.10.4 Information Provided by LSPGC

LSPGC indicated that it has developed a detailed design criteria for the project. (S-7) LSPGC indicated that it would have a construction manager, inspectors, and a quality manager at the project site and provided a detailed procurement and construction inspection plan. (C-1) LSPGC indicated that its primary STATCOM design and construction firm would provide a material yard and provide a comprehensive materials management program and indicated that procurement specifications require a comprehensive program of inspection and factory acceptance testing. (C-2) LSPGC indicated that it does not expect any outages for the project due to the location of the site and the point of change of ownership for the interconnection facilities. (C-3)

LSPGC indicated that it would utilize an internal staff, in close coordination with its proposed STATCOM design and construction firm and its primary engineering firm to perform detailed constructability review and that it has completed initial constructability review and has incorporated this information. (C-4) LSPGC indicated that it has exclusive options for the property for the STATCOM and has completed desktop and field environmental surveys necessary to begin regulatory and permitting but that it has not applied for any permits for the project. (C-5) LSPGC indicated that it would maintain a master project schedule that would incorporate all tasks and indicated that that its STATCOM design and construction firm and primary engineering firm would maintain a detailed project planner using Primavera software. (C-6) LSPGC indicated that it would not employ any special construction techniques (C-7) and that neither LSPGC nor any of its affiliates has been subject to any fines related to construction in the last five years. (C-8)

3.10.5 Information Provided by SEGG for Proposals 1 and 2

SEGG provided design details for the STATCOM and SVC, for its proposals 1 and 2, respectively, and switchyard. (S-7) SEGG indicated that its proposed construction contractor would implement a QA/QC program, provided a detailed list of inspections and testing for all phases of the project, and indicated that the construction contractor utilizes an integrated quality management system that connects all elements of the project. (C-1) SEGG indicated that its construction contractor would establish office and yard locations, coordinate purchase orders of materials, and receive, inventory, and stockpile the material. (C-2) SEGG indicated that it anticipates that no clearances would be needed for construction and that it would take two to three days to string each of the spans from the switchyard dead end to the PG&E dead end structure. (C-3)

SEGG indicated that it would conduct a comprehensive constructability review of the project through various teams and provided a detailed list that would be included in the constructability review. (C-4) SEGG indicated that its construction contractor would review all right-of-way and substation easement requirements and coordinate with environmental contractors to ensure the timing of permitting and that implementation of mitigation measures is carried out. (C-5) SEGG indicated that its construction contractor has broken the schedule into milestones for engineering, procurement, and construction, would develop a baseline schedule within 30 days of SEGG's selection as the approved project sponsor that would be maintained using Primavera software, and would provide a three-week look-ahead on a weekly basis. (C-6) SEGG indicated that no special construction techniques would be required (C-7) and that SEGG and its affiliates have had no notices of violation in the last five years. (C-8)

3.10.6 <u>Information Provided by SPT1</u>

SPT1 provided detailed designs for the STATCOM and switchyard (S-7). SPT1 indicated that as part of the Q/C program all construction activities would be inspected, including civil work and work on large pre-fabricated structures, and that offsite inspection, review of factory testing, and third party testing would be provided. (C-1). SPT1 provided the criteria that would be used to locate material yards and indicated that materials would be received and sequenced to support the construction activities and that contractors would be responsible for inspecting their materials. (C-2) SPT1 indicated that it, SPC, SCS, or an approved third party would coordinate with the ISO and transmission providers for clearances and review of energization and commissioning practices. (C-3)

SPT1 indicated that constructability reviews would be performed at 30%, 60%, and 90% of project completion, wherein the design and equipment selected would be checked to comply with standards and specifications. (C-4) SPT1 indicated that easements would be obtained as part of project siting and that pre-construction permits are included in the project schedule. (C-5) SPT1 indicated that it would track the project schedule using Primavera or MS Project software with an itemized list of all major planned construction activities, and that the schedule would be tracked with weekly and monthly updates. (C-6) SPT1 indicated that it would use typical construction techniques for this project (C-7) and that it has not received any notices of violation in the last five years. (C-8)

3.10.7 <u>Information Provided by Tenaska</u>

Tenaska provided design details for the STATCOM and switchyard. (S-7) Tenaska provided procedures it would follow concerning schedule, walk-around and subcontractor inspections, quality and safety checks, and checks on construction phases. (C-1) Tenaska indicated that its project management team would coordinate delivery and receipt of materials, inventory and properly store materials, identify storage methods, including indicating that larger material may be stored outside, and provide periodic inventory and material checks. (C-2) Tenaska indicated that the proposed location and associated construction activities for the 500 kV switching station and STATCOM would not require de-energization of PG&E's existing 500 kV transmission line and that the required loop lines to interconnect with PG&E's existing 500 kV transmission lines are outside of the project sponsor's scope. (C-3)

Tenaska provided procedures for (1) review of design, pursuant to which substation engineering drawing check sheets would be used and changes or clarifications would be made as needed, (2) design verification, (3) release for purchasing and construction, and (4) design changes. (C-4) Tenaska indicated that it has executed a site acquisition agreement and obtained site control. Tenaska indicated that it has also completed preliminary biological resources and cultural resources surveys, and would implement all necessary pre-construction permit conditions and mitigation measures prior to mobilization and start of construction in August 2022. (C-5) Tenaska indicated that its team scheduling process would include summary, requirements and scope, developing quality, safety, environmental, and project plans, work breakdown and scheduling, and monitoring and control of project work and stakeholder engagement. (C-6) Tenaska indicated that the site would not require any special techniques for access roads or permanent roads and that no helicopter work would be required. (C-7) Tenaska indicated that an affiliate paid a fine to the Pennsylvania Department of Environmental Protection/Pennsylvania Fish and Boat Commission in connection with the inadvertent discharge of horizontal directional drilling mud slurry. (C-8)

3.10.8 Information Provided by TransCanyon

TransCanyon provided detailed design information for the STATCOM and switchyard. (S-7) TransCanyon indicated that it would be responsible for ensuring the project is constructed in accordance with design, specifications, permit conditions, safety requirements, environmental constraints, and applicable laws and regulations and indicated that it would use in-house resources to manage QA/QC of construction and to perform environmental surveys. (C-1) TransCanyon indicated that its proposed EPC contractor and STATCOM firm would have the overall responsibility for material management for the project and that it would be the responsibility of the construction contractors to receive, inspect, store, and deploy project materials and provided a copy of the EPC contractor's and STATCOM firm's material management program. (C-2) TransCanyon indicated that it would establish one material yard that would also serve as the project headquarters. TransCanyon indicated that it expects that each transmission element would require planned outages during energization of the project and that these outages would be of short duration, required to energize the new switchyard and perform end-to-end testing between the switchyard and Round Mountain Substation and Table Mountain Substation. (C-3)

TransCanyon indicated that it has completed an initial constructability review and would perform additional constructability reviews at other key phases of the project, indicated that its EPC contractor's and STATCOM firm's design quality control plan identifies six distinct quality control review subtasks, which are scheduled for all projects, and indicated that the EPC contractor and STATCOM firm has developed specific construction specifications to apply to the project. (C-4) TransCanyon indicated that it has executed a purchase option agreement for land for the project and indicated that any mitigation for the project would be implemented and tracked as part of mitigation monitoring. (C-5) TransCanyon indicated that it would use a critical path schedule using Primavera software and provided a copy as an attachment, and indicated that standard progress reports would be issued by its EPC contractor to TransCanyon. (C-6) TransCanyon indicated that after review of the subsurface conditions in the area, it has identified micropiles as a suitable alternative to deep drilled shaft concrete foundations to reduce cost and expedite scheduling (C-7), and indicated that neither TransCanyon nor its parent organizations have incurred any construction-related fines in the last five years. (C-8)

Maintenance Practices

(Section 1 – Executive Summary, Section 3 – General Project Information, QS-1, QS-4, P-1, O-1, O-2, O-3, O-4, O-5, O-6, O-7, O-8, O-9, O-10, O-11, O-12, O-13, O-14, O-17, O-19)

3.10.9 Information Provided by HWT for Proposals 1, 2, 3, 6, 7, and 8

HWT indicated that it has an existing corporate service agreement with NEER for operating services that are provided by OSI. HWT indicated that OSI provides O&M services for NEER as well as third party generation owners. HWT indicated that the OSI field operations team that would support the project is responsible for O&M on approximately 205 substations and 1,190 circuit miles of lines, up to 500 kV. (QS-1)

HWT indicated that it and its affiliates have experience with owning, operating, and maintaining reactive support devices and its associated control systems with more than 500 MVAr of SVC, 360 MVAr of synchronous condensers, 8,000 MVAr of transmission level manually switched capacitors, and 3,000 MVAr of series compensation. HWT indicated that, in addition, it would be able to leverage TBC operations and maintenance staff who operate and maintain the two TBC converter stations, which each have a STATCOM capability of a maximum reactive power of +/- 300 MVAr at zero MW. HWT indicated that the total power transformer capability operated and maintained by HWT affiliates is more than 160,000 MVA, of which 140,000 MVA is subject to NERC jurisdiction. (O-6)

HWT stated that it has experience owning, operating, and maintaining 130 MVAr of STATCOM. (QS-1)

HWT indicated that its affiliate, FPL, has put in place a comprehensive condition assessment and pro-active maintenance program for all of its 500 kV facilities to ensure their continued reliability. (P-1)

HWT indicated that it has access to more than 700 in-house power system professionals, including technicians and other staff with expertise in all aspects of transmission and substation equipment installation, maintenance, and repair. (QS-1, QS-4, O-6)

HWT indicated that the Lone Star system operations control center in Austin, Texas and the Transmission Performance & Diagnostics Center in South Florida located at the Jupiter West facility would serve as hubs for technical knowledge, as well as remote condition assessment and field asset health information in support of operations. HWT indicated it also would be able to leverage local support personnel located at transmission facilities as well as wind and solar facilities throughout California, including the Suncrest SVC project, TBC, and other facilities. HWT indicated that additionally it would have the option to leverage the TBC control center. (Section 3, QS-1, QS-4)

HWT indicated that NEET recently completed its acquisition of TBC, an HVDC project located in the San Francisco bay area and that HWT would leverage TBC to support the project O&M. HWT indicated that TBC has two voltage source converter STATCOMs and that its O&M staff is based in Pittsburg, California, two to four hours from the project site. HWT indicated that TBC staff has operating and maintenance experience on

STATCOMs in California under ISO control and interconnected to the PG&E system. (O-1)

HWT indicated that the project's O&M structure is based on the one used by existing NextEra companies, including both FPL and NEET. HWT indicated that there are no planned changes to the project sponsor's current organization to accommodate the proposed project. (O-1)

HWT provided resumes of OSI maintenance management team indicating 15 or more years of experience. (O-2)

HWT indicated that its O&M contractor OSI has signed a support services agreement with an emergency support vendor that would provide qualified personnel, tools, and equipment as are necessary to assist in substation, line and protection maintenance. (O-1, O-4)

HWT provided descriptions of responsibilities, qualifications and training requirements for several O&M positions. (O-4)

HWT indicated that to facilitate training, NextEra Energy University (NEU), NextEra's continuing education department, offers an array of business and technical courses specifically selected to meet the changing demands of the business environment and the needs of all employees. HWT indicated that a key training resource for the HWT O&M team is the College of Power Systems to ensure that only staff with prerequisite qualifications execute O&M activities.

For continuing education, HWT indicated that it would apply NextEra's formal program of skills re-certification to the project. HWT indicated that this program applies to NextEra personnel in the areas of high-voltage specialists, control and protection, control center dispatchers, engineering, switching, and safety, as well as general systems training. HWT indicated that training is focused on skill refreshing and re-certification and the majority of courses include an exit test. HWT indicated that training progress and records are tracked by NextEra's corporate learning management system.

HWT provided a list of example training courses required for HWT O&M personnel which included 19 NERC compliance web based training modules requiring certification on either an annual or a three-year frequency.

HWT indicated that the Field Operations team members receive both theory and hands-on maintenance training. (O-5)

HWT indicated that the existing NextEra O&M organization has a program of maintenance standards providing the capability to manage compliance to the provisions of the TCA, and the ISO transmission maintenance standards. HWT indicated that this capability is supported by NextEra O&M team members past experience with the TCA requirements and ISO transmission maintenance standards. HWT indicated that NextEra has well-established practices and procedures for transmission system operations and maintenance of its transmission and substation facilities, which are derived from FPL's O&M practices for its facilities. HWT indicated that its O&M team members have experience maintaining SVCs, STATCOMs, capacitors, series compensators, and synchronous condensers. HWT indicated that its affiliate Gulf Power owns and has operated and maintained two SVCs for the past four years. HWT indicated that it is integrating the operations of new FACTS assets into the ISO system: Suncrest SVC, and TBC HVDC STATCOM.

HWT indicated that NextEra inspection and maintenance practices cover all elements in the TCA Appendix C Sections 5.2.1 and 5.2.2 for operating voltages between 69-500 kV.

HWT indicated that one of its team members was a past voting member of the ISO's Transmission Maintenance Coordinating Committee and participated in the continuous development of maintenance procedures to support the ISO Transmission Standards.

HWT indicated that another one of its team members developed the operations and maintenance plan for Lone Star. In doing so, the team member coordinated work with Lone Star, NextEra, and FPL personnel to ensure implementation of comprehensive, industry leading maintenance processes and procedures to ensure that Lone Star would meet the required reliability and other service levels for a high voltage transmission utility in Texas. (O-6)

HWT provided a thorough description of the HWT vegetation management plan, which indicated that vegetation management would be provided by the OSI affiliate FPL vegetation management team and additional specialized vendor support.

HWT indicated that NextEra is currently managing 42,000 miles of transmission/distribution lines in Florida and over 1600 miles of transmission/distribution lines in 22 states and 3 provinces of Canada and that the project would be added to the existing NextEra vegetation management program.

HWT provided a copy of NEET vegetation management program manual, its vegetation management QA/QC procedures, and a sample vegetation outage investigation form. (O-7)

HWT indicated that NextEra's transmission businesses have well-established, reasonable practices and procedures for the operations and maintenance of its facilities, which are derived from FPL's practices for its transmission line and substation facilities. As evidence, HWT provided:

- 2019 FPL reliability report to the Florida Public Service Commission
- CPUC approval of HWT's wildfire mitigation plan 2019
- TBC most recent annual maintenance audit by the ISO

The TBC maintenance audit by the ISO provided by HWT included the following statements: "During this year's review, station maintenance had no findings, concerns, or deviations. Transmission line maintenance had no findings, concerns or deviations." (O-8)

HWT indicated that reliability metric subject matter experts would work within the delivery assurance team and would be responsible for transmission and substation availability/reliability reporting for facilities across all NERC regions. HWT indicated that this team would support the project's compliance with the ISO Maintenance Procedures.

HWT indicated that NextEra continuously logs the availability of its major transmission elements. HWT indicated that the subject matter expert identifies each event with a unique number, a start time, an end time, the event details, the cause code, the outage classification, the resources informed, and other various measurement tags and that multiple events are logged individually. HWT indicated that these reporting criteria would be used by NextEra for the project and align with the current availability reporting obligations stated in TCA Appendix C Section 4.3 for forced outages.

HWT indicated that its availability reports would be maintained in an asset information management system. HWT indicated that this system provides NextEra subject matter experts and management a central source to review availability data that can support internal and external benchmarking needs, and feed its routine and special report obligations to specific jurisdictions, such as the ISO.

HWT provided:

- An example reliability reporting user guide
- NextEra availability and performance indicators
- 2018 transmission and substations availability measures sample from HWT affiliate FPL.

HWT indicated that TBC, as an existing ISO PTO, already complies with ISO Maintenance Procedure 2 for outage and availability reporting. HWT indicated that the TBC procedure on availability monitoring identifies the process to collect availability measures in accordance with TCA Appendix C Section 4.3. (O-9)

HWT indicated that no changes or exceptions are required to the provisions of the TCA. (O-10)

HWT indicated that it does not foresee any applicable reliability criteria for which transmission owners are responsible that would require temporary waivers under TCA Section 5.1.6. (O-13)

HWT indicated that it would implement a specific spare equipment and parts strategy for the project based on system needs that are known at the time the transmission facilities become operational. (O-19)

3.10.10 Information Provided by LSPGC

LSPGC indicated that it would perform maintenance activities with internal staff supported by key contractors. LSPGC indicated that its operating and maintaining experience included over 300 miles of EHV transmission lines, four EHV substations, and associated facilities using the same organizational structure and key personnel as planned for the project.

LSPGC indicated that it intends to contract with its proposed STATCOM design and construction firm to conduct preventative and predictive maintenance, perform emergency repair, and complete major facility rebuilds for the STATCOM facility.

LSPGC identified a primary emergency response and maintenance contractor for the project that has offices in California and other places in the west and a large combined fleet of specialized electrical construction services equipment and workforce of qualified personnel. LSPGC indicated that the primary provider has provided staff and equipment to support many utilities through similar emergency response and maintenance agreements, including major utilities in California. LSPGC indicated that its primary emergency response and maintenance contractor has staff and equipment located in close proximity to the project in its California offices.

LSPGC identified a secondary emergency response and maintenance contractor for the project and would have the resources of the entire company available to it, including staff and equipment located in northern, central, and southern California.

LSPGC indicated that it would provide operations and maintenance services to the project. LSPGC indicated that the project would be operated by its modern control centers and its local maintenance and technical staff, utilizing other existing staff and outside resources for maintenance and emergency response. LSPGC indicated that the project would be incorporated into its existing programs with existing equipment, experienced staff, and trusted contractors to provide operational and cost efficiencies with reduced risks.

LSPGC indicated that it currently has five staff in its transmission maintenance group with an average experience of more than 15 years. It indicated that one additional field employee would be added in 2019, one additional substation technician dedicated to the project would also be added to support maintenance of the project and would be based in California near the project, and one electrical engineer located in northern California would be available to support the project. (Section 1, QS-1, QS-4)

LSPGC listed three recently constructed substations for which it has maintenance responsibility, including one that has series compensation facilities. (P-1)

LSPGC provided an organization chart showing an O&M director, compliance director, and planning engineer reporting to an asset manager, who would report to a senior vice president of operations. The chart shows its proposed STATCOM design and construction firm and emergency service providers reporting to a substation technician who would report through a maintenance supervisor to the O&M director. LSPGC indicated that the substation technician would perform routine substation maintenance and inspections, perform minor repairs, and oversee the outside contractors. LSPGC indicated that the substation technician and electrical engineer would be supported by its existing maintenance staff located in Amarillo, Texas.

LSPGC provided the following for its primary emergency response and maintenance contractor:

- A statement of qualifications
- A summary of staff, tools, vehicles, and equipment
- An executed emergency response and field service agreement

LSPGC indicated that its secondary emergency response and maintenance contractor has experience building and maintaining substations and transmission lines up through 500 kV.

LSPGC provided the following for its secondary emergency response and maintenance contractor:

- A statement of qualifications
- A summary of local staff, tools, vehicles, and equipment
- An executed emergency response and field service agreement

LSPGC indicated that its compliance staff would perform all compliance management for the project. LSPGC indicated that the project would be integrated into its NERC compliance program leveraging its existing policies and procedures, and its existing compliance staff located in Chesterfield, Missouri and Austin and Amarillo, Texas. LSPGC indicated that LS Power currently performs compliance management in the Electric Reliability Council of Texas (ERCOT) region and is in the process of integrating into the PJM, MISO, and ISO regions to perform compliance management for transmission assets beginning service in 2020. LSPGC indicated that no organizational changes are necessary to accommodate the project. (O-1)

LSPGC provided resumes for several of its proposed team members. (O-2)

LSPGC indicated that it has been operating and maintaining over 300 miles of EHV transmission lines, four EHV substations, and associated facilities over the past five years using the same organizational structure and key personnel as planned for the project.

LSPGC indicated that its primary emergency response and maintenance contractor has provided emergency response and restoration services to numerous utilities, including utilities located in California.

LSPGC indicated that its secondary emergency response and maintenance contractor has emergency response and maintenance contracts with numerous utilities around the country, including California. LSPGC indicated that the scope of services provided includes storm emergency restoration and maintenance for substations, transmission, and distribution facilities. (O-3)

LSPGC indicated that it employs staff with prior demonstrated qualifications, skills, and experience necessary to operate and maintain its assets. LSPGC listed the qualifications, certifications, and experience of its operations and field personnel.

LSPGC indicated that it utilizes internal and external training courses to ensure it has qualified, skilled, and experienced field maintenance personnel.

LSPGC indicated that substation maintenance staff have obtained or are pursuing Substation Maintenance Technician certification through the AVO Training Institute. LSPGC indicated that this certification program ensures staff have achieved certain performance knowledge, skills, and ability through training.

LSPGC indicated that it maintains a procedure and a list of qualified personnel, including individual contractor staff, who are allowed station access.

LSPGC indicated that its primary emergency response and maintenance contractor hires qualified labor, demonstrated through past employment and through current certification and that new employees are required to complete the new hire orientation, which is designed to ensure all new employees are aware of the firm’s safety policies and procedures. LSPGC indicated that all new employees are given a skills assessment to determine if further training is required.

LSPGC indicated that its secondary emergency response and maintenance contractor hires qualified labor, demonstrated through past employment and through current certification, and that new employees are required to complete the new hire orientation program, which includes OSHA transmission and distribution training. (O-4)

LSPGC indicated that for field personnel internal training is provided annually and whenever there is a change in job responsibilities or policy or procedures. LSPGC indicated that this training includes a number of topics, such as emergency action plans, fall protection, hazard communications, code of conduct, and switching. LSPGC indicated that its power staff must perform continuing education in order to maintain their substation maintenance technician certification and that personnel are required to complete annual coursework for satisfying continuing education requirements associated with their certifications.

LSPGC indicated that its proposed STATCOM design and construction firm offers comprehensive training programs for its personnel, which is performed through a combination of online learning, factory training, and on-the-job training.

LSPGC indicated that its primary emergency response and maintenance contractor has a "university" for training, consisting of an online training program that uses learning modules to deliver training to employees on a broad range of subjects, which vary by employee and applicability to jobs being performed.

LSPGC indicated that its secondary emergency response and maintenance contractor uses a comprehensive program to ensure regular and ongoing employee training and that training subjects and courses vary by employee and applicability to jobs being performed. (O-5)

LSPGC indicated that it would perform maintenance in accordance with its existing maintenance policies and procedures that it has successfully utilized for maintaining its existing assets.

LSPGC provided a copy of its transmission maintenance and inspection plan, which includes items such as inspection frequency and type, components to be inspected, qualifications of inspectors, and recordkeeping, and includes sections on transmission lines, substation equipment, and series compensation.

LSPGC provided a copy of its proposed STATCOM design and construction firm's STATCOM maintenance plan and indicated that upon selection as the approved project sponsor, it would incorporate relevant portions of the proposed STATCOM design and construction firm's maintenance plan into its transmission maintenance and inspection plan to fully comply with the maintenance standards described in Appendix C of the TCA.

LSPGC indicated that these existing plans and procedures include the elements listed in TCA Appendix C Sections 5.2.1 (Transmission Line Circuit Maintenance) and 5.2.2 (Station Maintenance). LSPGC indicated that it utilizes a computerized maintenance management system to produce notices and work orders to complete each task. (O-6)

LSPGC provided a sample of its existing transmission vegetation management policy and transmission vegetation management plan and indicated that this existing plan would be amended to accommodate specific vegetation management requirements for this project. (O-7)

LSPGC indicated that its computerized maintenance management system is Maximo, which is used to help manage its asset and maintenance workflow process and work orders.

LSPGC indicated that its vegetative management and maintenance plans and procedures were submitted to NERC during the audit process and that these procedures have been found to be in full compliance. LSPGC indicated that a key element of the implementation and documentation of this compliance is a detailed work order management system.

LSPGC provided sample inspection reports for substations and transmission lines, including right-of-way and vegetation, and an operations and maintenance report. The inspection reports indicated a detailed record of the work performed, measurements, and corrective actions taken. (O-8)

LSPGC indicated that it would collect the necessary data and retain necessary experienced resources to provide the project's availability measures in accordance with TCA Appendix C Section 4.3.

LSPGC indicated that it submits Transmission Availability Data System reports to NERC and included a table of availability of its transmission line assets for recent years. (O-9)

LSPGC indicated that it does not require any waivers under TCA Section 5.1.6. (O 13)

LSPGC indicated that its operations and maintenance group has experience managing emergency responses for wildfires, snow and ice storms, thunderstorms, hurricanes, and tornados.

LSPGC indicated it would complete emergency repairs with a combination of internal staff and outside contractors. LSPGC indicated it would have a local California-based substation technician and electrical engineer and would be able to respond within a few hours with its local staff and support of its local contractors. (O-19)

3.10.11 Information Provided by SEGG for Proposals 1 and 2

SEGG indicated that the project sponsor would be responsible for carrying out the siting, permitting, engineering, procurement, financing, construction, commissioning, and on-going operations and maintenance of the project.

SEGG indicated that it would engage in a comprehensive O&M services agreement with its proposed O&M services provider to perform O&M services and NERC compliance for the project. SEGG indicated that the project sponsor would register with NERC and WECC as a Transmission Owner and that it would also become a PTO with the ISO and execute the TCA for the project. (Section 3)

SEGG indicated that the project sponsor has assembled and formed a skilled and experienced team of a technology provider, EPC contractor, engineering company, environmental expert, and O&M services provider with the necessary knowledge, skill-set, and expertise to successfully undertake the design, construction, operation, and maintenance of the project in an efficient and cost effective manner. (QS-1)

SEGG indicated that O&M services for the project would be outsourced to a firm that has many years of experience and has thousands of employees in more than 150 offices and facility sites. SEGG provided a sampling of the firm's clients. (QS-4)

SEGG indicated that maintenance would be performed by its proposed O&M services provider. SEGG indicated that the firm has been involved with the construction, operations, and maintenance of 17 recently-constructed transmission line projects, of which it has provided maintenance services for six projects. SEGG indicated that the firm has been involved with the construction and maintenance of 20 recent substation projects, of which it has provided maintenance services for four projects. (P-1)

SEGG indicated that the project sponsor's O&M organization would be composed of an asset manager who would manage the project's O&M responsibilities through a long-term contract.

SEGG indicated that its O&M services provider would appoint a project manager to oversee all maintenance activities and to coordinate with the project sponsor as necessary. SEGG indicated that within the firm, the project manager would report to a senior operations director and be able to draw upon the firm's extensive back office support team in the areas of regulatory compliance and maintenance and engineering support. SEGG indicated that the project manager would draw specialist maintenance expertise and field service support under contracts with its proposed STATCOM and SVC vendor for the STATCOM and SVC, for proposals 1 and 2, respectively, and its proposed construction contractor for the switching station. (O-1)

SEGG indicated that the project manager would be responsible for directing all operations and maintenance activities at the facility and assuring that the facility is operated in compliance with applicable safety, environmental, and power grid requirements. SEGG indicated that the O&M services provider would take steps to ensure that the right candidate is selected. SEGG indicated that the project manager position would require a technical degree or equivalent work experience, ten years of power generation or similar experience, and at least three years of supervising technical, supervisory, and administrative personnel.

SEGG indicated that field personnel should have transmission, WECC power grid, and substation technical and leadership experience with a work history that demonstrates a pattern of accomplishments and advancement and that a Bachelor of Science degree in electrical engineering or equivalent would be desired. (O-4)

SEGG indicated that the O&M services provider's training program would be primarily focused on commercial operations of the facility and that the methods established in its manual would be equally applicable to the pre-commercial period of the project. SEGG indicated that during the operational phase, training would continue to revisit subject areas and to refresh and refine the knowledge and understanding of facility personnel.

SEGG indicated that elements of the training program include operations training, safety training, computer training, other training, EPC training, project manager training, and plant administrator training.

SEGG indicated that the training and certification requirements for the lineman would be through the International Brotherhood of Electrical Workers union, where each lineman is required to complete a 3-4 year apprenticeship program, with the requirements for substation electricians being the same as for linemen. (O-5)

SEGG indicated that standard maintenance practices employed by its O&M services provider and its subcontractors' maintenance practices include all the elements listed in TCA Appendices C Sections 5.2.1 and 5.2.2.

SEGC generally described its proposed maintenance practices, indicating the maintenance would be carried out per manufacturer's recommendations and warranty requirements and that maintenance would include issues identified by inspections both aerial and visual.

SEGG indicated that maintenance practices employed by its O&M services provider include the following:

- Patrols and inspections
- Perimeter fences and gates
- Conductor and shield wire maintenance
- Disconnects and pole-top switches
- Battery systems
- Circuit breakers
- Direct current transmission components
- Reactive power components
- Protective relays systems
- Station service equipment
- Transformers and regulators
- Structures and foundations maintenance
- Structure grounds maintenance
- Guys and anchors maintenance
- Insulator, bushing, and arrestor maintenance
- Rights-of-way maintenance
- Vegetation management (O-6)

SEGG provided a general description of a generic vegetation management plan.

SEGG indicated that the vegetation management plan would comply with the National Electric Safety Code, American National Standards Institute A300 Part 7, and the International Society of Arboriculture best management practices. (O-7)

SEGG indicated that its O&M services provider and its subcontractors (SEGG's STATCOM and SVC vendor, for proposals 1 and 2, respectively, and construction contractor) would generally not be required to submit regulatory filings, although some of the utility clients that they support do have this obligation. SEGG indicated that the O&M services provider has experience with implementation and compliance with standards for inspection, repair, and replacement of similar facilities.

SEGG indicated that the firm is an operations and maintenance service provider and typically works for the facilities owner using a "fee at risk" model. SEGG indicated that under this model, a significant portion of the O&M services provider's fee is not earned unless it can demonstrate that it is compliant with its standards, to the satisfaction of the owners.

SEGG indicated that the O&M services provider has a governance and compliance group for internal controls and has been developing a computer-based compliance management system that would be used to monitor and enforce compliance with both regulatory and company standards with the intent to identify and address issues of non-compliance before they potentially impact the operation of the facility. SEGG indicated that this system would be in place prior to commercial operations of the project.

SEGG indicated that its O&M services provider's experience with implementation and compliance with standards for inspection, maintenance, repair, and replacement of similar facilities includes proven programs and scalable processes (operations, management, inspection, maintenance and repair, compliance, and subcontractor services) that enable successful O&M services on high-voltage transmission line segments associated with power plants operated by the O&M services provider. (O-8)

SEGG provided a list of seven transmission lines for which its O&M services provider had O&M experience. The list included lines from 34.5 kV to 500 kV. The total length of all the lines listed was less than 100 miles. No substation facilities were listed. (O-14)

SEGG indicated that the O&M services provider would submit an annual report within 90 days of the end of the calendar year that would describe the project's availability measures performance, which would include all forced outage records, including the date, start time, end time, affected transmission facility, and cause of the outage.

SEGG indicated that the O&M services provider's agreements typically have key performance indicators that are useful in assessing actual performance against targets in technical performance and commercial performance.

SEGG indicated that at this time it does not anticipate any changes or exceptions to the provisions of the TCA to be required. (O-10)

SEGG indicated that there are no temporary waivers that would be required or requested under TCA Section 5.1.6. (O-13)

SEGG indicated that it would follow a restoration plan program, which would include a plan specific to the project area based on the characteristics of the project footprint, applicable NERC requirements, and ISO restoration program documentation guidance. SEGG provided a sample emergency operating plan from its proposed O&M services provider.

SEGG indicated that the project manager would work to have the project join a regional joint cooperation pool with neighboring utilities and that once a member, the project manager would manage the operational relationship and be the point of contact with the pool. (O-19)

3.10.12 <u>Information Provided by SPT1</u>

SPT1 indicated that SCS would support SPC, which would provide engineering and construction support for SPT1, and would be responsible for post-construction monitoring of project operations and maintenance. SPT1 indicated that SPC, SCS, or an approved third party would be responsible for project operations and taking actions at the direction of the ISO. (Section 3)

SPT1 indicated that its affiliates own, operate, and maintain extensive generation and transmission facilities across the United States. SPT1 indicated that SCS provides services on behalf of these affiliated companies, including transmission-related operations and maintenance activities and operation of the Southern Company systems.

SPT1 indicated that it would utilize its equipment manufacturer for turnkey EPC services and maintenance, pursuant to a fixed-price EPC contract. SPT1 indicated that its equipment manufacturer is currently responsible for serving North American power systems and rail transportation with electrical and electronic products, systems, and services. (Section 3)

SPT1 indicated that it would be managed by a team consisting of SPC's transmission, legal, state and local affairs, project finance, commercial optimization, environmental permitting and compliance, EPC project management, project development, operations and maintenance, and business origination departments. SPT1 indicated that, additionally, this team would be supported by the following SCS groups: transmission equipment and standards, substation physical, civil, and electrical design, engineering and construction services, supply chain, bulk power operations, legal, and risk management. (QS-1)

SPT1 indicated that maintenance of the facility would be performed by its equipment manufacturer and provided the scope and schedule for planned maintenance, which provides an overview of the type of maintenance that would be performed by its equipment manufacturer on a yearly basis. SPT1 indicated that the warranty and maintenance work that its equipment manufacturer would perform would be managed by the director of renewable operations. SPT1 indicated that its equipment manufacturer's corporate support is located in Pennsylvania and would also utilize local technicians located in California. (O-1)

SPT1 provided resumes for its O&M team indicating many years of utility experience. (O-2)

SPT1 indicated that affiliate-owned transmission facilities are generally maintained according to Southern Company corporate maintenance and testing programs that follow common industry practices and includes both time-based and condition-based maintenance activities. SPT1 indicated that programs are reviewed periodically to address lessons learned, technology improvements, and industry best practices. SPT1 indicated that equipment outages are reviewed to determine root cause and corrective action plans are developed and implemented to prevent recurrence, as appropriate.

SPT1 indicated that its equipment manufacturer is currently contracted to perform service on approximately 15 of its SVC and STATCOM facilities installed throughout North America. SPT1 indicated that its equipment manufacturer has on staff factory-trained field technicians who can perform routine maintenance on the STATCOM valves, cooling, and controls. SPT1 indicated that its equipment manufacturer also has the capability to incorporate other substation maintenance specialties (*e.g.*, protective relaying, instrument transformers, circuit breakers, etc.) into its maintenance service offerings. (O-3)

SPT1 indicated that Southern Company follows a three-step process of screening and testing to ensure only appropriately qualified, skilled, and experienced persons are hired to perform maintenance and construction for substation work. (O-4)

SPT1 indicated that lineman and substation personnel typically have over 2,000 hours of training a year and this includes both classroom and field training. SPT1 indicated that classroom training includes learning the basics of the entire electrical system from generation through transmission, distribution, the meter, and electrical safety and tools. SPT1 indicated that field testing includes theory and application of pole climbing, pole and major substation inspections, personal protective equipment, and fall protection. SPT1 indicated that annually lineman and substation personnel are required to take written test as well as classroom and field training to maintain their qualifications for construction, maintenance, and operation of Southern Company electrical systems. (O-5)

SPT1 indicated that Southern Company's maintenance practices are considered best-in-class. SPT1 indicated that based on this experience and credibility, it would comply with all maintenance standards as described in Appendix C of the TCA. SPT1 indicated that all elements listed in TCA Appendix C Sections 5.2.1 and 5.2.2 are within the scope of SPT1's maintenance standards except for direct current transmission components, which are not applicable to this project. (O-6)

SPT1 provided a copy of the SPC vegetation management program for transmission lines for existing procedures and historical practices for managing rights-of-way for transmission facilities. (O-7)

SPT1 indicated that affiliate-owned transmission facilities are generally maintained according to Southern Company corporate maintenance and testing programs that follow common industry practices and includes both time-based and condition-based maintenance activities. SPT1 indicated that programs are reviewed periodically to address lessons learned, technology improvements, and industry best practices. SPT1 indicated that equipment outages are reviewed to determine root cause, and corrective action plans are developed and implemented to prevent recurrence, as appropriate. SPT1 indicated that maintenance activities (including repair and replacement) are scheduled and tracked via an in-house maintenance management tool ensuring that maintenance intervals adhere to NERC requirements. SPT1 indicated that Southern Company has successfully demonstrated compliance with NERC requirements for inspection and maintenance of transmission facilities in multiple audits.

SPT1 provided sample field services reports for activities at SPC generating plants. (O-8)

SPT1 indicated that it would adhere to all required availability measure reporting required by the ISO. (O-9)

SPT1 indicated that it does not anticipate any necessary changes to the TCA. (O-10)

SPT1 indicated that it intends to engage PG&E or another already existing ISO PTO to potentially operate or maintain at least the switchyard portion of the project. SPT1 indicated that this seems a logical fit for PG&E given that four of its transmission lines would terminate into the switchyard. (O-12)

SPT1 indicated that it does not anticipate that any temporary waivers under TCA Section 5.1.6 would be required. (O-13)

SPT1 indicated that it would utilize a primary control center in order to maintain adequate and reliable data acquisition facilities related to the control and monitoring of transmission system facilities within its TOP area.

SPT1 indicated that it would retain and utilize the appropriate data to assess its availability measures performance based upon forced outage records. SPT1 indicated that all forced outages would be documented, including the date, start time, end time, affected transmission facility, and the probable cause(s) if known, and saved for annual reporting purposes. SPT1 indicated that it would submit its availability measures performance to the ISO at a minimum on an annual basis. (O-17)

SPT1 indicated that it would make available all resources, including local maintenance teams, to respond to and comply with emergency conditions. SPT1 indicated that its local maintenance teams would be located in northern California, with the contractor to be selected based on appropriate resources, experience, and capabilities operating in the ISO area and working with STATCOMs. SPT1 indicated that emergency operating procedures would be created and integrated with the ISO and system transmission operators to ensure proper coordination. SPT1 indicated that due to the limited scope of this facility, plans would place priority on the restoration and operation of the facility to work in conjunction with PG&E's and the ISO's system restoration plans. SPT1 indicated that the NERC TOP function for SPT1 would be monitored 24/7 and have the capability to quickly initiate a response to emergency conditions. SPT1 indicated that it expects to be able to contact and dispatch local maintenance teams to respond to emergency conditions within an hour of the emergency event.

SPT1 indicated that its equipment manufacturer would have California-based maintenance resources in place when the STATCOM is put into service to provide expeditious responses to any events that occur during the warranty and contracted maintenance term.

SPT1 provided the Cactus Flats Wind generating station emergency operating plan and indicated that it was SPC's most recently approved emergency operating plan. SPT1 indicated that the emergency operating plan for the project should be similar in form and substance to this sample plan. (O-19)

3.10.13 Information Provided by Tenaska

Tenaska indicated that it has not chosen contractors to manage the execution, construction, or O&M of the project but identified a potential O&M service provider. (Section 3, O-1)

Tenaska indicated that it has begun discussions with potential third-party suppliers and contract providers, including a proposed O&M service provider. (QS-1)

Tenaska indicated that overall responsibility for the operations and maintenance services to be provided would lie with its O&M service provider under a contractual relationship with the project sponsor. Tenaska indicated that the its O&M service provider team would report to Tenaska asset management personnel.

Tenaska indicated that for its proposed O&M service provider, the project manager would report to a senior operations director and be able to draw upon the O&M service provider's extensive back office support team in the areas of regulatory compliance and maintenance and engineering support. Tenaska indicated that the project manager would draw specialist maintenance expertise and field service support from the equipment manufacturer for the STATCOM and the EPC contractor for switchyard and transmission facilities under contract. (O-1)

Tenaska provided resumes for its own and its proposed O&M service provider's key personnel indicating many years of utility experience. (O-2)

Tenaska indicated that it has extensive experience managing compliance with its operations and maintenance procedures.

Tenaska indicated that its assessment program is used to review its own compliance with its procedures. Tenaska indicated that this program requires that it review its program compliance on a tri-annual, rotating basis, at each of the facilities that it operates and maintains. Tenaska indicated that the assessment program also reviews the implementation of best practice notifications issued by its corporate operations and maintenance management team.

Tenaska indicated that its proposed O&M service provider is an operations and service provider and typically works for the facilities owner using a "fee at risk" model. Tenaska indicated that under this model, a significant portion of the O&M service provider's fee is not earned unless it can demonstrate that it is compliant with its standards, to the satisfaction of the owners. Tenaska indicated that this helps it to align its interests with ensuring that its site team is aligned with executing against its standards.

Tenaska indicated that its proposed O&M service provider has a governance and compliance group for internal controls. Tenaska indicated that its O&M service provider has been developing a computer-based compliance management system that would be used to monitor and enforce compliance with both regulatory and its O&M service provider company standards. (O-3)

Tenaska indicated that it has more than a 30-year track record of attracting and hiring talented, qualified personnel for its fleet of generation facilities across the nation.

Tenaska indicated that because its proposed O&M service provider is expected to provide O&M staffing for this project, it provided information based on its O&M service provider's training and qualification programs.

Tenaska indicated that its proposed O&M service provider hires field personnel with transmission, WECC power grid, and substation technical and leadership experience with a work history that demonstrates a pattern of accomplishments and advancement.

Tenaska indicated that for its O&M service provider's field personnel a Bachelor of Science degree in electrical engineering or equivalent is desired. (O-4)

Tenaska provided a description of the its proposed O&M service provider's training program, including the following lineman and electrician certification requirements:

- Each lineman is required to complete a 3-4 year apprenticeship program, the OSHA transmission and distribution 10-hour and 20-hour training programs, and training in first aid, CPR, bucket rescue, pole top rescue, grounding, and rigging.
- Substation electricians are required to undertake the same training as lineman and also have specialty training for the various equipment on which they are required to be working. (O-5)

Tenaska listed maintenance practices addressing the major areas listed in TCA Appendix C Sections 5.2.1 and 5.2.2 and described the processes it would follow. (O-6)

Tenaska indicated that it has multiple generation facilities with generator tie lines, as well as one 80+ mile transmission line, that meet the vegetation management requirements under NERC reliability standard FAC-003-4. Tenaska indicated that it has vegetation management programs that meet NERC requirements. Tenaska indicated that its proposed O&M service provider, which has extensive experience with vegetation management requirements, would be providing these services. Tenaska indicated that vegetation management specific to the substation footprint would be considered.

Tenaska indicated that its vegetation management program complies with the National Electric Safety Code, ANSI A300 Part 7: American Operations Integrated Vegetation Management and Electric Utility Rights-of-Way and the International Society of Arboriculture best management practices. Tenaska indicated that the project sponsor would comply with vegetation management standards required by the NERC and WECC vegetation management guidelines as outlined in NERC reliability standard FAC-003. (O-7)

Tenaska indicated that its proposed O&M service provider's O&M experience with implementation and compliance with standards for inspection, maintenance, repair, and replacement of similar facilities includes proven programs and scalable processes (operations, management, inspection, maintenance and repair, compliance, and subcontractor services) that enable successful O&M services on high-voltage transmission line segments associated with power plants operated by the provider. Tenaska indicated that its O&M service provider's successful experience thus far with transmission and distribution projects demonstrates that these core capabilities translate across various types of electric power projects.

Tenaska indicated that although its proposed O&M service provider and Tenaska do not have audit reports or regulatory filings for similar facilities, Tenaska included some example audit reports and several assessment document templates that its O&M service provider uses to ensure compliance with its standards for implementation, inspection, maintenance, repair, and replacement. The documents include blank maintenance assessment procedure and reliability assessment procedure templates.

Tenaska indicated that its proposed O&M service provider would apply the same overarching strategic and tactical approaches when performing O&M services for this project that it has applied to the power generation facilities and transmission lines for which its O&M service provider provides (or has provided) O&M services. Tenaska listed six transmission lines totaling about 50 miles for which its O&M service provider has provided O&M services. (O-8)

Tenaska indicated that as part of its 30-year history operating power generation facilities, it participated in the NERC Generating Availability Data System, as did its proposed O&M service provider.

Tenaska indicated that its proposed O&M service provider performs Generation Availability Data System and Transmission Availability Data System reporting across its fleet of generation and transmission facilities, as required by NERC. Tenaska indicated that its O&M service provider is currently supporting reporting for more than 170 facilities.

Tenaska indicated that its proposed O&M service provider has executed more than 300 operations and maintenance agreements during is history. (O-9)

Tenaska indicated that the addition of this project to the ISO controlled grid would not require any changes or exceptions to the Transmission Control Agreement. (O-10)

Tenaska indicated that the PTO would not need to take exceptions to TCA Section 5.1.6. (O-13)

Tenaska indicated that it and its proposed O&M service provider have decades of experience operating large scale generation facilities across the nation, which includes various emergency plans.

Tenaska indicated that its proposed O&M service provider's emergency operating plans include emergency situations that may result in imminent or direct threats to public safety or threaten or impair its O&M service provider's ability to provide reliable transmission service to its client. Tenaska listed emergency situations related to transmission lines as examples.

Tenaska provided a sample copy of the emergency plan to be followed by its proposed O&M service provider's personnel to respond to a major facility fire.

Tenaska indicated that the project manager would work to have the project join a regional joint cooperation pool with neighboring utilities, and once a member, the project manager would manage the operational relationship and be the point of contact with the pool.

Tenaska indicated that its proposed O&M service provider has O&M support staff located in northern California. Tenaska indicated that response time would be three to six hours for emergencies and 48 hours for non-emergencies. Tenaska indicated that its O&M service provider and Tenaska would endeavor to enter into a mutual support agreement with PG&E to reduce response times as necessary. (O-19)

3.10.14 <u>Information Provided by TransCanyon</u>

TransCanyon indicated that it has signed an MOU with PacifiCorp to provide operations support and to facilitate maintenance services for the project. TransCanyon indicated that its ability to use the services of PacifiCorp would be subject to regulatory approvals related to affiliate transaction rules, as described in Section 3.9.12 above. (Section 3, O-1)

TransCanyon indicated that by using PacifiCorp to provide operations and facilitate maintenance services, TransCanyon would have the advantage of integrating the operations of the project into PacifiCorp's existing infrastructure and that this capability would be even more valuable considering the fact that PacifiCorp is placing a STATCOM in service at its Latham Substation in Wyoming. TransCanyon indicated that the same team that would support the Latham Substation facility with compliance policies, systems, and highly trained, qualified staff would be in place and would be able to directly apply expertise from the Latham Substation facility for the benefit of the project. (Section 3, QS-1)

TransCanyon indicated that it would further utilize a leading STATCOM manufacturer and its construction contractor to perform onsite preventative and corrective maintenance activities and to respond on site to emergencies and to perform emergency work. TransCanyon indicated that it has negotiated a maintenance service agreement with the STATCOM manufacturer for scheduled preventative maintenance services for the STATCOM devices and the 500 kV breakers in the switchyard and a maintenance service agreement with its construction contractor for monthly inspection and emergency response services for the project and scheduled preventative maintenance services for the remainder of the switchyard. (Section 3, QS-1, O-1)

TransCanyon indicated that PacifiCorp would facilitate the maintenance activities specified in these agreements on behalf of TransCanyon. TransCanyon indicated that that PacifiCorp would provide the office asset management functions of maintenance scheduling and record keeping and that PacifiCorp would dispatch its construction contractor for emergency response and would facilitate maintenance outages, clearances, and tagging for its construction contractor or its STATCOM manufacturer to perform emergency response, monthly equipment inspections, and scheduled preventative maintenance activities at the project. (Section 3, QS-1)

TransCanyon indicated that its maintenance lead is a PacifiCorp employee with more than 20 years of experience and expertise. (QS-1, QS-4)

TransCanyon indicated that its team is primarily composed of team members from affiliates of its two parent companies, PNW and BHE. (P-1)

TransCanyon indicated that the PacifiCorp maintenance planning team populates, maintains, and manages the centralized system of record for applicable transmission and distribution assets managed throughout the company's service territory in Oregon, Washington, and California. (O-1)

TransCanyon provided resumes for key PacifiCorp and outside contractor team members indicating many years of experience. (O-2)

TransCanyon indicated that its construction contractor is well-positioned as a suitable contractor for performing maintenance and emergency response support for the project. TransCanyon indicated that the construction contractor has a local California presence as well as subsidiaries that can provide management, workers, material, and fleet resources that are conveniently located throughout California, providing accessibility throughout the region. TransCanyon indicated that its construction contractor and affiliates hold maintenance agreements with several utility clients throughout the western United States.

TransCanyon indicated that its proposed STATCOM manufacturer meets its customers' maintenance needs via a complete life-cycle care agreement. TransCanyon indicated that the STATCOM manufacturer's agreement represents production availability insurance for FACTS installations, providing the most cost-effective solution to maximize production up-time, availability, and reliability. TransCanyon indicated that it would engage its STATCOM manufacturer primarily for preventative maintenance, corrective maintenance, and phone support. (O-3)

TransCanyon indicated that its construction contractor would ensure that only those persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations would be involved in project execution. TransCanyon indicated that all of the contractor's craft employees have been technically trained through the IBEW-NECA Joint Apprenticeship Training Committee.

TransCanyon indicated that its STATCOM manufacturer has designed certification levels for service engineers and specialists and that each certification level has a skill set defined that requires mandatory e-training and face-to-face trainings with hands-on sessions to become fully acquainted with the equipment. TransCanyon indicated that to develop the competency of service engineers, special courses are designed, and a consolidated training portal has been established. TransCanyon indicated that all the manufacturer's contractors' employees receive a detailed site induction regarding the site rules. TransCanyon indicated that the STATCOM manufacturer requires suppliers or contractors undergo an in-depth qualification process defined per the manufacturer's processes. TransCanyon listed six elements of the manufacturer's contractor management program that cover planning, implementation, monitoring, and review. (O-4)

TransCanyon indicated that its construction contractor dedicates significant time and effort to ensure training and orientation programs provide employees with the latest, most comprehensive, and accurate information possible. TransCanyon indicated that this ensures they are properly trained in hazard recognition and mitigation when it comes to protecting themselves and others on the job, and are well-versed in their abilities to maintain compliance with all contractor, OSHA, and Department of Transportation safety rules, procedures, and guidelines. TransCanyon provided a list of the topics included in its construction contractor's new hire orientation program.

TransCanyon indicated that in addition to new hire orientation, regular and ongoing training is conducted for all of the construction contractor's employees. TransCanyon indicated that the contractor maintains documentation of all training and ensures employees obtain any necessary re-certifications.

TransCanyon indicated that its STATCOM manufacturer maintains a continuous skills development program that focuses on the competency development of its engineers and specialists and that the program is aimed at enabling professional development and meeting the manufacturer's strategic plan by developing functional competencies. (O-5)

TransCanyon indicated that PacifiCorp's asset management team would work with PacifiCorp grid operations to schedule and confirm that all maintenance activities are performed in order to comply with all maintenance standards described in Appendix C of the TCA. TransCanyon indicated that PacifiCorp would confirm that the project complies with all NERC reliability standards by including all project maintenance activities in PacifiCorp's transmission maintenance and inspection plan. TransCanyon indicated that PacifiCorp has a rigorous substation maintenance program that includes this type of plan. TransCanyon indicated that this includes routine maintenance of all the project equipment including, but not limited to, reactive support devices, transformers, and switches.

TransCanyon indicated that PacifiCorp would facilitate the work activities specified in the maintenance contract between TransCanyon and its construction contractor on behalf of TransCanyon. TransCanyon indicated that the PacifiCorp asset management team would ensure that the construction contractor performs inspections and responds to emergencies per the maintenance contract. TransCanyon indicated that the PacifiCorp asset management team would track, record, and provide compliance records for inspections and emergency response for the project.

TransCanyon indicated that its construction contractor's maintenance standards meet or exceed the maintenance standards described in Appendix C of the TCA.

TransCanyon indicated that PacifiCorp would facilitate the work activities specified in the maintenance contract between TransCanyon and its proposed STATCOM manufacturer on behalf of TransCanyon.

TransCanyon indicated that its STATCOM manufacturer has developed a comprehensive maintenance plan that defines specific maintenance activities for all equipment in the project. (O-6)

TransCanyon indicated that after the environmental permitting processes for the project are completed, a vegetation management plan would be developed for the project.

TransCanyon indicated that the vegetation management plan would include guidelines and instructions for vegetation removal methods (mechanical, manual, and chemical), and right-of-way access and would also include procedures for complying with all requirements of conditions or directives established in the environmental permitting processes and in accordance with any applicable laws and applicable NERC reliability standards.

TransCanyon indicated that its construction contractor would execute the transmission vegetation management plan for the project under PacifiCorp's management. TransCanyon described PacifiCorp's existing vegetation management philosophy for transmission lines as utilizing integrated vegetation management best practices wherever possible to conduct cover type conversion and to cultivate stable, low-growing plant communities and provided a copy of PacifiCorp's vegetation management plan. (O-7)

TransCanyon indicated that PacifiCorp's maintenance planning department develops maintenance and inspection work plans, as informed by its transmission maintenance and inspection plan, and tracks its annual transmission and substation maintenance requirements using the company's system of record, as well as a monthly transmission inspection progress report. TransCanyon indicated that this progress report includes requirement maintenance activities and verifies that all tasks are performed to completion and on schedule.

TransCanyon provided an example of PacifiCorp's tracking of its annual transmission and substation maintenance requirements and monthly transmission inspection progress reports. (O-8)

TransCanyon indicated that through its affiliated operating companies it is familiar with control chart methodology described in the TCA. TransCanyon indicated that APS has monitored availability performance of its 500 kV and 345 kV transmission lines using this process for over 10 years.

TransCanyon provided examples of APS availability measures using the control chart methodology.

TransCanyon indicated that APS also uses other methodologies including forced outage per 100-mile year, NERC Transmission Availability Data Systems, and Average Service Availability Index that are also employed in the industry but has the capability of capturing all the necessary data to compute availability performance based on the methodology described in the TCA.

TransCanyon indicated that PacifiCorp also develops numerous reliability and availability measurements including forced outage per 100-mile year, NERC Transmission Availability Data Systems, and Average Service Availability Index that are also employed in the industry.

TransCanyon provided a figure showing the past ten years data for PacifiCorp transmission availability. (O-9)

TransCanyon indicated that adding the project to the ISO controlled grid would not require any changes or exceptions to the provisions of the TCA. (O-10)

TransCanyon indicated that its proposed construction contractor has committed to a four-hour response time for emergency assistance.

TransCanyon indicated that its proposed STATCOM manufacturer's technical personnel would be available 24 hours a day, 365 days a year for technical support if necessary and would mobilize to the project site as soon as possible if required. TransCanyon indicated that the STATCOM manufacturer has engineers at offices in northern and southern California. (O-19)

Operating Practices

(Section 3 - General Project Information, QS-1, QS-4, P-1, O-1, O-2, O-3, O-4, O-5, O-11, O-12, O-13, O-14, O-15, O-16, O-17, O-18, O-19, O-20)

3.10.15 Information Provided by HWT for Proposals 1, 2, 3, 6, 7, and 8

HWT indicated that it plans to operate and maintain the project through agreements with its experienced affiliates with support from equipment manufacturers and specialty contractors. In particular, HWT indicated that it plans to utilize NextEra's existing pool of high-voltage technicians and existing field support resources already located in California to support existing power generation and transmission assets. HWT indicated that these personnel would be responsible for providing 24/7 on-call response, site switching and safety, routine inspection and maintenance, and general site care duties. HWT indicated that, in addition, NEET's in-house transmission operations team located in Austin, Texas would monitor and control the project's operations and that this in-house team is both ISO and NERC certified and would have operated the Suncrest SVC project in the ISO balancing authority area for several years before this project is placed in service. In addition, HWT indicated that it can leverage TBC existing operations, which operates equipment in the ISO balancing authority area similar to that proposed for this project. HWT indicated that it may also utilize equipment manufacturers and contractors to support operations and maintenance. (Section 3)

HWT indicated that it has an existing corporate service agreement with NEER for operating services that are provided by NEER Operating Services, LLC (OSI). HWT indicated that OSI would provide both the local field operations and system operations for the project. HWT indicated that OSI provides O&M services for NEER as well as third party generation owners. HWT indicated that the OSI field operations team that would support the project is responsible for O&M on approximately 205 substations and 1,190 circuit miles of lines, up to 500 kV. HWT indicated that it would leverage both internal and contractor resources for the safe, reliable, and efficient operations and maintenance of the project.

HWT indicated that the Lone Star system operations control center in Austin, Texas and the Transmission Performance & Diagnostics Center in South Florida located at the Jupiter West facility would serve as hubs for technical knowledge, as well as remote condition assessment and field asset health information in support of operations for the project. HWT indicated that it would be able to leverage local support personnel located at transmission facilities as well as wind and solar facilities throughout California, including the Suncrest SVC project, TBC, and a number of other facilities. Additionally, HWT indicated that it would have the option to leverage the TBC control center. (QS-1)

HWT indicated that key individuals who would be involved in the project include professionals who have led and collaborated on the operation of numerous prior transmission and other major infrastructure projects. (QS-4)

HWT indicated that operations and maintenance would be performed by its affiliate, OSI and that, reporting through OSI, the operations function would be performed by its Lone Star affiliate. HWT indicated that OSI would also receive support from a vendor and received technical service support through HWT's affiliates. HWT indicated that TBC would also provide operations support.

HWT indicated that compliance management would report directly to HWT be performed by an operational compliance director, with support from operational corporate services.

The organization charts provided by HWT indicate that the above organizations report to the senior director of NEET operations. HWT indicated that the senior director of NEET operations is responsible for all project O&M obligations and is based in Jupiter, Florida and that the project's operations would be led by the OSI field operations lead based at the project.

HWT indicated that system operational control would be provided by HWT affiliate Lone Star and that the project's single point of contact for the ISO would be the Lone Star control center based in Austin, Texas.

HWT indicated that the project's O&M structure is based on the one used by existing NextEra companies, including both FPL and NEET.

HWT indicated that it would leverage TBC to support the project O&M. HWT indicated that TBC has two voltage source converter STATCOM devices and that its O&M staff is based in Pittsburg, California, two to four hours from the project site. HWT indicated that TBC staff has operating and maintenance experience on STATCOMs in California under ISO control and interconnected to PG&E's system.

HWT indicated that in 2010 WECC endorsed TBC as a TOP certified by NERC. HWT indicated that TBC has in place a reliability standards agreement with the ISO that outlines the responsible entity for compliance with NERC requirements and lists any delegated tasks that either party may be responsible for performing. HWT indicated that this agreement has been implemented into a coordinated functional registration (CFR) agreement between TBC and the ISO. HWT indicated that TBC's operating practices address full compliance with applicable reliability criteria, including NERC reliability standards and ISO Maintenance Procedures 1-7. HWT provided documentation supporting those claims. (O-1)

HWT provided resumes of key operations management personnel indicating many years of utility experience. The provided resumes also indicated key operations personnel are NERC certified. (O-2)

HWT indicated that it would follow NextEra's established human resources policies, processes, and procedures. HWT indicated that NextEra has a formal hiring process managed by its human resources department in coordination with the hiring business unit.

HWT indicated that the system operator Lone Star's philosophy is to hire experienced operations personnel who have previously obtained the necessary NERC certifications.

HWT provided descriptions of responsibilities, qualifications, and training requirements for several O&M positions, including system operator, field operations leader, and field operations high voltage technician. (O-4)

HWT indicated that to facilitate training, NextEra Energy University, NextEra's continuing education department, offers an array of business and technical courses specifically selected to meet the changing demands of the business environment and the needs of all employees. HWT indicated that a key training resource for the HWT O&M team is the College of Power Systems to ensure that only staff with prerequisite qualifications executes O&M activities.

HWT provided a copy of a NEET operations training plan, which outlines the Lone Star operator training program. HWT indicated that the goal is to establish and maintain a NERC-approved training program for operations personnel that have the primary responsibility, either directly or through communications with others, for the real time operation of the interconnected bulk electric system and for positions directly responsible for complying with NERC standards.

HWT provided example training courses that would be required for HWT O&M personnel, which included 19 NERC compliance web based training modules requiring certification on either an annual or a three-year frequency.

HWT indicated that all records of completed training would be available in the learning management system and that reports could be pulled at any time. HWT indicated that Lone Star and HWT have the responsibility of ensuring that training is completed by every required employee by specified dates and that this information is reported to NextEra's compliance and responsibility organization during the bi-annual internal self-assessment of their reliability standards processes. HWT indicated that the training is leveraged by Lone Star and HWT for process improvements and that Lone Star has experience revising procedures as a direct result of training. (O-5)

HWT indicated that the NERC functions applicable to the project are the NERC Transmission Owner (TO), Transmission Operator (TOP), and Transmission Planner.

HWT indicated that in late 2019 it would register as a NERC TO and NERC Transmission Planner in WECC in connection the Suncrest SVC project going in service and that these registrations would also cover this project.

HWT indicated that for its Suncrest SVC project WECC and the Texas Reliability Entity agreed that HWT's NERC TOP function would be performed by Lone Star under its existing NERC TOP registration and that ERCOT and the ISO have also agreed to this plan. HWT indicated that the NERC TOP function for this project would also be covered under the Lone Star NERC TOP registration. (O-11)

HWT indicated that it would contract with its affiliate Lone Star for NERC TOP services as well as the TO and Transmission Planner functions that would be integrated into HWT in connection with the Suncrest SVC project in late 2019.

HWT indicated that Lone Star was originally certified as a NERC TOP in 2012 and that NERC and the Texas Reliability Entity affirmed Lone Star's TOP certification in 2016 following a review by the Texas Reliability Entity due to the relocation of the primary control center to a new building. HWT provided copies of the NERC TOP certification and NERC review letter.

HWT indicated that NextEra's compliance and responsibility organization would monitor HWT and Lone Star execution of their NERC functional programs to ensure compliance with the reliability standards or requirements associated with the project.

HWT indicated that NextEra's compliance and responsibility organization met with WECC and the Texas Reliability Entity in early 2019 to vet Lone Star's obligations pertaining to operating the Suncrest SVC project in WECC under Lone Star's existing TOP registration that has been audited by the Texas Reliability Entity. HWT indicated that NextEra's compliance and responsibility organization subsequently met with ERCOT and ISO to share the agreed upon framework. (O-12)

HWT indicated that it would follow NextEra's documented NERC reliability standards internal compliance program, which has been provided to every employee who works directly on NERC reliability standards compliance.

HWT indicated that both NextEra's compliance and responsibility organization and its internal audit department report through the Senior Vice President of Internal Audit and Compliance. HWT indicated that NextEra's compliance and responsibility organization has responsibility for the internal oversight of compliance with NERC standards.

HWT indicated that it does not foresee any applicable reliability criteria for which transmission owners are responsible that would require temporary waivers under TCA Section 5.1.6. (O-13)

HWT provided a summary of NextEra's NERC violations, which indicated that between 2014 and 2018 there have been eleven audits and three spot-checks conducted across the NextEra registered entities resulting in only two violations of operations and planning standards. HWT provided a list of the violations.

HWT provided Lone Star's two latest NERC and Texas Reliability Entity draft audit reports. The draft 2017 report indicated that there were no findings in the ten NERC TO and TOP operations and planning reliability standard requirements audited and seven potential non-compliances in the 19 NERC TO and TOP reliability standard requirements audited. The 2014 report indicated that based on the evidence provided, no findings were noted for the standards and applicable requirements in scope for this engagement. (O-14)

HWT provided TBC's latest NERC audit report. The report stated: "Based on the results of this Compliance Audit, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement." (O-14)

HWT indicated that in July 2019 the ISO and HWT affiliate Lone Star planned to begin the process of establishing a CFR agreement for compliance with NERC requirements for HWT's Suncrest SVC project. HWT indicated that the CFR requirement for the proposed project would be covered by the proposed 2019 agreement.

HWT indicated that Lone Star has reviewed the way its approach aligns with existing CFR agreements, specifically the approach taken by PG&E and TBC in establishing their project-related CFR with the ISO.

HWT indicated that NextEra O&M team members have experience creating and executing CFR agreements for previous projects with the ISO and ERCOT. HWT indicated that Lone Star currently operates under a CFR agreement with ERCOT. (O-15)

HWT provided a list of applicable agreements describing:

- Project agreement types
- Purpose/scope
- Project stakeholders/interfacing parties

The list included:

- Interconnection Agreement
- Special Facilities Agreement
- Transmission Control Agreement

- Reliability Standards Agreement
- Operating procedure/protocols
- Communication and project points of contact procedure
- Maintenance practices -- lines
- Maintenance practices -- substations
- Outage management process
- Emergency restoration procedure
- Facilities rating
- System model

(O-16)

HWT indicated that its affiliate, Lone Star, owns the primary control center and backup control center, including the energy management system (EMS) infrastructure, that would perform the system operations function for the project.

HWT indicated that the interconnection with the ISO would be dual scanned from both HWT data centers. HWT indicated that redundant inter-control center communications protocol (ICCP) or International Electrotechnical Commission standards servers would be used to exchange telemetry and SCADA system data with the ISO, PG&E, and other neighboring entities via the ICCP interconnection with the ISO.

HWT indicated that the primary and backup control centers are located in Texas. HWT indicated that both control centers are connected via redundant and diversely routed communications networks to NEET primary and backup data centers in Florida where the EMS servers reside.

HWT indicated that its SCADA schemes would be used to gather power delivery equipment availability data, that equipment operating times would be synchronized to allow for the capture of outages, and that this functionality would support the data collection requirements of TCA Appendix C Section 4.3. (O-17)

HWT indicated that it is currently in the process of becoming a signatory to the TCA in connection with the Suncrest SVC project and would be in compliance with TCA Sections 6.1, 6.3, 7, 9.2, and 9.3 when the Suncrest SVC project enters service.[9] (O-18, O-19)

HWT indicated that its affiliates are responsible for the operation and maintenance for over 8,700 circuit miles of the bulk electric system and that all of these circuits and associated facilities have operational processes, procedures, and maintenance practices that comply with their applicable reliability criteria and NERC's operation and planning reliability standards.

HWT provided copies of several operating procedures addressing requirements of TCA Sections 6.1, 6.3, and 7.

HWT indicated that NextEra processes and standards cover all elements in TCA Section 14 for operating voltages between 115-500 kV.

[9] Since submitting its proposal, HWT has become a signatory to the TCA.

HWT indicated that it is currently working to establish field and system operations for its Suncrest SVC project, working closely with the ISO and San Diego Gas & Electric Company. (O-18)

HWT indicated that NextEra companies are experienced at devising recovery plans. HWT indicated that the NextEra emergency preparedness business unit would ensure organizational readiness across all threats and hazards to the project. HWT provided a description of its proposed emergency preparedness plans for the project. (O-19).

HWT indicated that the project would not be subjected to any encumbrance. (O-20)

3.10.16 Information Provided by LSPGC

LSPGC indicated that it would use internal staff and existing facilities to perform all operations and compliance activities for the project. LSPGC indicated that its operating and maintaining experience included over 300 miles of EHV transmission lines, four EHV substations, and associated facilities using the same organizational structure and key personnel as planned for the project. (Section 3, O-1, O-3)

LSPGC indicated it would provide operations and maintenance services to the project. It indicated that the project would be operated by its existing control centers and its local maintenance and technical staff, utilizing other existing staff and outside resources for maintenance and emergency response. LSPGC indicated that the project would be incorporated into its existing programs with existing equipment, experienced staff, and trusted contractors to provide operational and cost efficiencies with reduced risks. (QS-1)

LSPGC indicated that the project team has experience designing, constructing, and interconnecting the DesertLink 1,018 MVAr of 500 kV series compensation with the systems of ISO PTOs and has experience working with the ISO to establish operational control and compliance programs. LSPGC indicated that this execution team would have the full support of its internal functional expertise, including accounting, legal, land acquisition, permitting, regulatory, engineering, construction management, operations and maintenance, and financing.

LSPGC indicated that its operations staff would perform all operations for the project out of its existing, modern control centers located in Austin, Texas. LSPGC indicated that its control centers (fully functioning primary and backup locations) were constructed to operate, monitor, and control its EHV transmission lines and substations.

LSPGC indicated that the control center is fully operated in-house and is staffed 24 hours per day, seven days a week. LSPGC indicated that it currently has nine staff in its transmission operations group with an average experience of over 15 years. LSPGC indicated that the operations group includes five NERC-certified transmission system operators. LSPGC indicated that its operations manager, senior operations engineer, and transmission training and safety specialist are also NERC certified transmission system operators to provide redundancy in system operations.

LSPGC indicated that two additional transmission system operators would be added in 2019 as it integrates operations in the PJM region. LSPGC indicated that no additional operations staff would need to be added to operate the project.

LSPGC indicated that it currently has eight staff in its information technology and operational technology group dedicated solely to transmission operations with an average experience of 20 years. LSPGC indicated that no additional information technology or operational technology staff would need to be added to operate the project. (QS-4)

LSPGC provided information on 10 transmission line projects (above 200 kV) and 11 substation projects where it has direct experience. LSPGC indicated that it had operations responsibility for six of the projects. (P-1)

LSPGC indicated that its operations staff would perform real-time operations monitoring and control, planned outage coordination, and switching coordination for the project. LSPGC indicated that its control centers located in Austin, Texas would serve as the point of contact for the ISO. LSPGC indicated that no organizational changes are necessary to accommodate the project.

LSPGC indicated that its compliance staff would perform all compliance management for the project. LSPGC indicated that the project would be integrated into its NERC compliance program leveraging its existing policies and procedures and its existing compliance staff located in Chesterfield, Missouri and Austin and Amarillo, Texas. LSPGC indicated that LS Power currently performs compliance management in the ERCOT region and is in the process of integrating into the PJM, MISO, and ISO regions to perform compliance management for transmission assets beginning service in 2020. LSPGC indicated that no organizational changes are necessary to accommodate the project. (O-1)

LSPGC provided resumes for key operating and compliance management positions indicating many years of experience. (O-2)

LSPGC indicated that it employs staff with prior demonstrated qualifications, skills, and experience necessary to operate and maintain its assets.

LSPGC listed the qualifications, certifications and experience of LSPGC operations and field personnel and provided its policies to ensure that its personnel performing or supporting real-time operations on the bulk electric system are qualified and have the necessary experience.

LSPGC indicated that all transmission system operators are required to hold at a minimum a current NERC certification of either:

- Transmission Operator NERC certification (minimum) or
- Reliability Coordinator NERC certification.

(O-4)

LSPGC indicated that it uses a quality training database to build training plans, track initial and annual training, and track reliability related tasks that are company-specific on-the-job training to ensure its transmission system operators are fully trained.

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 the transmission system operator shift schedule is designed with training weeks built-in to ensure each transmission system operator receives required training throughout the year. LSPGC indicated that transmission system operators are required to pursue ongoing education to maintain their certifications, which are renewed every three years. LSPGC indicated that to facilitate regular operating training, the SCADA and EMS system has an operator training simulator. (O-5)

LSPGC indicated that it would register with NERC as a TO, TOP, and Transmission Planner for the project. (O-11)

LSPGC indicated that it would perform all NERC functions for the project and would not contract any of the functions. (O-12)

LSPGC indicated that the project would be integrated into LSPGC's NERC compliance program leveraging its existing policies and procedures. LSPGC indicated that it has a strong culture of compliance with a dedicated and experienced compliance team to ensure all applicable reliability standards are met.

LSPGC indicated that all LSPGC O&M personnel have compliance obligations and responsibilities with experience across multiple operating jurisdictions, including the ISO.

LSPGC indicated that the compliance director, with the support of compliance analysts, would develop and implement compliance policies and procedures, participate in regional NERC compliance organizations, and lead compliance audits.

LSPGC indicated that the asset manager would be responsible for all NERC compliance for the project.

LSPGC indicated that the operations and maintenance director would oversee the training and NERC certification for its transmission system operators, and information technology and operational technology cybersecurity policies and implementation.

LSPGC indicated that it maintains a comprehensive list of operating procedures, policies, operating guides, and documentation to ensure consistent and compliant system operations. LSPGC indicated that it would use its existing regulatory compliance software to maintain compliance with all NERC TOP, TO, and Transmission Planner requirements.

LSPGC indicated that it does not require any waivers under TCA Section 5.1.6. (O-13)

LSPGC indicated that its affiliate Cross Texas Transmission currently owns approximately 300 miles of 345 kV transmission lines, three 345 kV switching stations and one 345 kV series compensation station. LSPGC indicated that its affiliate GBT-South owns 75% of 231 miles of 500 kV single circuit transmission lines, one 500 kV substation, eight miles of 345 kV single circuit transmission lines, and two 345 kV series capacitors. LSPGC indicated that neither entity has had any instances of non-compliance with NERC requirements.

LSPGC indicated that the Texas Reliability Entity conducted an operations and planning audit of LSPGC assets in 2016. The audit reports provided by LSPGC indicated that

LSPGC was found to have no findings of non-compliance with all the NERC reliability standards that were included in the scope of the audit. (O-14)

LSPGC indicated that if selected as the approved project sponsor, LSPGC would file a PTO application and work with the ISO on the division of responsibility for NERC reliability standards. LSPGC indicated that it has experience with this as Cross Texas Transmission and ERCOT have a similar CFR agreement. LSPGC indicated that its affiliate, DesertLink, is currently working through this division of responsibility for NERC reliability standards with ISO for the Harry Allen to Eldorado transmission project. LSPGC indicated that this division of responsibility would serve as the template for division of responsibility for this project.

LSPGC provided a sample CFR matrix for the DesertLink project. (O-15)

LSPGC indicated that the primary division of responsibility related to NERC reliability standards would be between LSPGC and the ISO. LSPGC indicated that this agreement would define the responsibilities and authority regarding NERC compliance responsibilities for the NERC functions of Planning Authority, Transmission Owner, Transmission Service Provider, Balancing Authority, and Transmission Planner.

LSPGC indicated that the responsibilities and authority regarding the NERC Transmission Operator function between LSPGC and adjacent transmission operator(s) would be defined in an interconnection agreement with each respective adjacent transmission operator.

LSPGC indicated that if future generation is connected to the project, the division of responsibility and authority between LSPGC and any generation owner(s) or generation operator(s) would be defined in an interconnection agreement with any generation owner or operator. (O-16)

LSPGC stated that all of its existing facilities have fully functioning data acquisition equipment. LSPGC provided a copy of an existing Cross Texas Transmission operating procedure documenting how it provides adequate and reliable telecommunications facilities to maintain the reliability of the bulk electric system. LSPGC indicated that similar equipment would be installed for the project to ensure adequate, reliable, and redundant data transmission and acquisition capabilities. LSPGC indicated that the communication infrastructure utilized for the project would provide reliable and secure multi-path links among the primary and backup controls centers, the ISO, and the project.

LSPGC indicated that the primary and backup control centers would provide sufficient geographic diversity while being close enough to allow transmission system operators to relocate in less than two hours (as required by NERC). LSPGC indicated that the backup control center fully mirrors the primary control center and complete transfer of control could occur without losing any monitoring or control capabilities.

LSPGC indicated that data communications are diversely routed and firewalled at multiple locations. LSPGC indicated that data communication infrastructure at each of its control centers would provide for multiple layers of redundancy among (1) the ISO, WECC, and the primary control center; (2) the ISO, WECC, and the backup control center; (3) the project and the primary control center; (4) the project and the backup control center; and (5) the primary control center and the backup control center. LSPGC indicated that real-time telemetry data would be transmitted and received by the project via dual internet connections with a cellular modem backup and could be accessed through the ISO and WECC via ICCP.

LSPGC indicated that it would utilize appropriate data recording and reporting collected by it from operations of the project to provide an annual report to ISO within 90 days after the end of each calendar year describing its availability measures performance based on forced outage records. (O-17)

LSPGC indicated that its transmission operations control center has certified operating personnel, outage coordination personnel, and support staff. LSPGC indicated that its operating personnel and support teams at the control center 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 it currently performs planned outage coordination for all its transmission lines, substations, and associated facilities.

LSPGC provided samples of its operating procedures.

LSPGC indicated that it would be responsible for planned outage coordination for the project. LSPGC indicated that it currently performs planned outage coordination for all its transmission lines, substations, and associated facilities. LSPGC indicated that its operations staff would coordinate with ISO primarily through the ISO outage management system. LSPGC indicated that it would maintain a rolling plan for maintenance activities necessary to support the project and ensure outage information for routine maintenance is known more than a year in advance. LSPGC indicated that a detailed outage schedule and event sequencing plan would be prepared to support maintenance activities and tentatively schedule resources and equipment to conduct the maintenance activity, including specialized equipment as necessary.

LSPGC indicated that it would be responsible for supervising and performing switching for the project and that all switching would be supervised by NERC-certified transmission system operators and performed by qualified switchmen.

LSPGC indicated that it would provide system monitoring and initial forced outage response on a 24/7 basis. LSPGC indicated that it would continually monitor and be prepared to respond to forced outages.

LSPGC indicated that it would be responsible for performing all major equipment re-energization for the project and would follow the process and procedures detailed in its re-energization procedures for major equipment to place major equipment back in service. (O-18)

LSPGC indicated that its operations and maintenance group has experience managing emergency responses for wildfires, snow and ice storms, thunderstorms, hurricanes, and tornados. LSPGC indicated that in the event of a system emergency, its staff would coordinate with the ISO as necessary and assist to alleviate the emergency.

LSPGC indicated that its transmission system operating and support personnel are trained regularly on emergency operations procedures and are familiar with the various reporting requirements associated with system emergencies.

LSPGC indicated it would incorporate the project into its existing emergency operation and response plans. LSPGC provided copies of its emergency response plan and Cross Texas Transmission's emergency operations plans and existing system restoration plan.

LSPGC indicated it would complete emergency repairs with a combination of internal staff and outside contractors. LSPGC indicated it would have a local California-based substation technician and electrical engineer and would be able to respond within a few hours with its local staff and support of its local contractors. (O-19)

LSPGC indicated that the project would not be subject to any encumbrance on the ISO's operational control. (O-20)

3.10.17 Information Provided by SEGG for Proposals 1 and 2

SEGG indicated that the project sponsor would be responsible for carrying out operations of the project. SEGG indicated that it would engage in a comprehensive O&M services agreement with its proposed O&M services provider, to perform O&M services and NERC compliance for the project. SEGG indicated that a subsidiary of the O&M services provider would perform the functions of the NERC Transmission Operator for the project. SEGG indicated that this entity is registered with NERC as a Transmission Operator. SEGG indicated that the project sponsor would register with NERC and WECC as a Transmission Owner and that it would also become a PTO with the ISO and would execute the TCA for the project. (Section 3)

SEGG indicated that the project sponsor has assembled and formed an exclusive alliance with a highly skilled and experienced team, including an O&M services provider, with the necessary knowledge, skill-set, and expertise to successfully undertake operation of the project in an efficient and cost effective manner. (QS-1)

SEGG indicated that its O&M services provider has many years of experience and has thousands of employees in more than 150 offices and facility sites. SEGG provided a sample of the O&M services provider's client base, which included a number of utilities throughout the U.S. (QS-4)

SEGG listed a 138 kV transmission line for which the subsidiary for project operations of its O&M services provider had operating responsibility starting in 2018 and two transmission lines (138 kV and 69 kV) for which it had operating responsibility starting in 2019. SEGG also listed one 500 kV transmission line for which its O&M services provider had operating responsibility starting in 2013.

SEGG indicated that its O&M services provider has been involved with the operations of three substation projects, which include reactive support devices and one of which is 500 kV. (P-1)

SEGG indicated that its O&M organization would be composed of an asset manager who would manage the project's O&M responsibilities through a long-term contract with the O&M services provider. SEGG indicated that operations responsibilities would be managed by a subsidiary of the O&M services provider, through its president and 24/7 desk.

SEGG indicated that the O&M services provider would appoint a project manager to coordinate with its subsidiary for project operations and with the project sponsor as necessary. SEGG indicated that within the O&M services provider, the project manager would report to a senior operations director and be able to draw upon the provider's extensive back office support team in the areas of regulatory compliance and maintenance and engineering support.

SEGG indicated that the subsidiary of its O&M services provider would be responsible for day-to-day compliance with the TOP standards and that operations responsibilities would be managed by the subsidiary. SEGG indicated that the location of the control center that would serve as the single point of contact for the ISO is in Houston, Texas. (O-1)

SEGG provided resumes for key management positions, including several with operating responsibilities indicating many years of experience. (O-2)

SEGG indicated that to become a qualified operator (both initially and bi-annually thereafter), an employee must complete the qualifications standard for the applicable operator position (e.g., control room operator and assistant plant operator).

SEGG indicated that field personnel should have transmission, WECC power grid, and substation technical and leadership experience with a work history that demonstrates a pattern of accomplishments and advancement and that a Bachelor of Science degree in electrical engineering or equivalent would be desired. (O-4)

SEGG indicated that all of the system operators of the subsidiary for project operations of its O&M services provider are required to be NERC certified at the reliability coordinator level and PJM certified. (O-5)

SEGG indicated that the subsidiary for project operations of its O&M services provider is registered with NERC as a Transmission Operator. SEGG indicated that the subsidiary for project operations of its O&M services provider and its parent have extensive experience as the registered entity for a number of NERC functions, including TOP, Balancing Authority, and Generation Operator, and while the latter standards are unlikely to apply to this project, the processes that are used for the TOP role have benefitted from the experience gained in the other functional areas. (O-11)

SEGG indicated that its proposed O&M services contractor would perform NERC services internally from the resources and expertise of its headquarters-based NERC department and would not contract out NERC services. (O-12)

SEGG indicated that the subsidiary for project operations of its O&M services provider, based out of Houston, Texas, has been providing control area or balancing authority services since its inception in 2001 and is currently registered as a Balancing Authority with NERC. SEGG indicated that in addition to its primary control center in Houston, the subsidiary for project operations of its O&M services provider has a backup control center in another part of Houston and redundant data centers in Utah and Pennsylvania. SEGG indicated that the subsidiary for project operations of its O&M services provider has approximately 30 employees and 15 of them staff its control center on a rotating shift schedule of three personnel per shift. SEGG indicated that each control center operator, and a majority of its corporate management team, are certified to the Reliability Coordinator level and also hold PJM certification. SEGG indicated that its ongoing training needs are provided by its in-house certified training staff.

SEGG indicated that the subsidiary for project operations of its O&M services provider has been supporting transmission operations for its clients in the Southwest since 2009, when the subsidiary for project operations of its O&M services provider started providing TOP services for multiple-mile 500 kV generation ties and interconnections. SEGG indicated that while these generation ties were subject to a TOP “light” set of standards, the subsidiary for project operations of its O&M services provider oversaw system operations from its control room in Houston, providing switching, emergency response, outage coordination, monitoring, data exchange, compliance, etc.

SEGG indicated that in 2019 the subsidiary for project operations of its O&M services provider became a registered TOP within MISO. SEGG indicated that the subsidiary for project operations of its O&M services provider is currently supporting five TOP clients in the Eastern Interconnection with varying scopes of work.
SEGG indicated that the TOP clients that the subsidiary for project operations of its O&M services provider supports in the Eastern Interconnection are made up of small to medium sized municipalities that own transmission systems that are part of the bulk electric system. SEGG indicated that using its control center in Houston, the subsidiary for project operations of its O&M services provider provides TOP services for those clients’ transmission lines, substations, and associated electrical components, including transformers, breakers, and disconnects.

SEGG described a compliance milestone process for compliance with NERC reliability standards to be managed via e-mail to schedule milestone meetings and include appropriate team members to assure that compliance milestones are met. SEGG indicated that meeting minutes would be created and distributed for review and tracking. SEGG indicated that no temporary waivers would be required or requested under TCA Section 5.1.6. (O-13)

SEGG provided a list indicating that its proposed O&M services provider, as the Transmission Operator, has operating experience for transmission lines ranging from 0.5 miles at 500 kV, less than 22 miles at 138 kV, and 36.82 miles at 69 kV that are subject to NERC compliance requirements. SEGG indicated that its O&M services provider continues to have fewer violations per registered entity and lower penalties per violation than the industry. (O-14)

SEGG indicated that its O&M services provider would plan to enter into a CFR agreement with the ISO similar to the existing CFR agreements on file at the ISO website.

SEGG indicated that its O&M services provider would register or maintain an existing registration for the TOP function for the duration of the service agreement for the project and perform the TOP services for the project, as required. (O-15)

SEGG indicated that a transmission operator services agreement would be negotiated and executed between the project sponsor and the O&M services provider. SEGG indicated that the project would not interact with any Generator Owner, Generator Operator, Distribution Provider, or Transmission Service Provider. SEGG did not identify the need for an interconnection agreement with PG&E. (O-16)

SEGG indicated that the subsidiary for project operations of its O&M services provider would conduct all aspects of 24x7 transmission operations, which would include a control center (based in Texas) and backup control center facilities. SEGG indicated that in addition the subsidiary for project operations of its O&M services provider has two remote data centers that are “hot-hot” to ensure no loss of data could occur.

SEGG indicated that the subsidiary for project operations of its O&M services provider would:

- Staff 24 x 7 NERC-certified system operators assigned to the project.
- Allocate tools and applications for real-time monitoring by system operators, including alarming, status indications, and limits.
- Establish real-time data exchange to support real-time monitoring, including equipment status, megawatts, voltage, and reactive flows.
- Develop and implement normal operations and emergency response procedures in coordination with O&M personnel, interconnected entities performing the NERC functions of Generation Operator and Transmission Operator, as well as the Reliability Coordinator.
- Initiate analysis of protection system operations in coordination with O&M personnel to determine if the protection scheme is operating correctly.
- Submit an annual report to the ISO within 90 days after the end of each calendar year describing project availability measures performance, which annual report would be based on forced outage records, including the date, start time, end time, affected transmission facility, and problem cause.

(O-17)

SEGG indicated that its O&M services provider would:

- Develop and coordinate plans and goals consistent with the goals of the project.
- Operate the project safely and in compliance with all regulatory requirements and project agreements.
- Work closely with its subsidiary for project operations, which would utilize its 24/7 monitoring capabilities of the project and would coordinate ISO operating orders and switching actions with tagging and clearance practices that are accepted in the industry.
- Achieve high availability through diligent planning, work scheduling, preventative maintenance execution, and readiness to respond and remediate unscheduled outages while operating the project to approved plans and budgets.
- Operate the transmission facilities in compliance with the ISO Tariff, ISO protocols, the operating procedures (including emergency procedures in the event of communications failure), and the ISO’s operating orders unless the health and safety of operating personnel or the public would be endangered.
- Operate and maintain the transmission facilities ensuring to take proper care of the safety of personnel and the public and act in accordance with good utility practice, applicable law, and applicable reliability criteria.
- Obtain approval from the ISO pursuant to the ISO Tariff before taking out of service and returning to service any facility, except in cases involving immediate hazard to the safety of personnel or the public or imminent damage to facilities.
- Notify the ISO promptly in the event of a forced outage.

- After a system emergency or forced outage, restore service of the transmission facilities under ISO's operational control as soon as possible and in the priority order determined by the ISO.
- Provide the ISO with a written report describing the circumstances and the reasons for any forced outage.
- Forecast and coordinate maintenance outage plans in accordance with Section 9 of the ISO Tariff.
- Notify the ISO of any faults on the ISO controlled grid or any actual or anticipated forced outages as soon as aware of them.
- Take all steps necessary to prevent forced outages.
- Return to operation, as soon as possible, any facility under the ISO's operational control that is subject to a forced outage.

(O-18)

SEGG indicated that it would follow a restoration plan program, which would include a plan specific to the project area based on the characteristics of the project footprint, applicable NERC requirements, and ISO restoration program documentation guidance. SEGG provided a sample emergency operating plan from its proposed O&M services provider.

SEGG indicated that the project manager would work to have the project join a regional joint cooperation pool with neighboring utilities and that once a member, the project manager would manage the operational relationship and be the point of contact with the pool.

The information provided by SEGG regarding operating practices in the event of emergencies listed emergency situations related to transmission lines. (O-19)

SEGG indicated that it is not aware of any encumbrances to the project at this time. (O-20)

3.10.18 Information Provided by SPT1

SPT1 indicated that SCS would support SPC, which would provide engineering and construction support for SPT1, and would be responsible for post-construction monitoring of project operations and maintenance. SPT1 indicated that SPC, SCS, or an approved third party would be responsible for project operations and taking actions at the direction of the ISO. (Section 3)

SPT1 indicated that its affiliates own, operate, and maintain extensive generation and transmission facilities across the United States. SPT1 indicated that SCS provides services on behalf of these affiliated companies, including transmission-related operations and maintenance activities and operation of the Southern Company systems. SPT1 also noted that the operation of the facility would be handled by either a third party or internally in SPC's remote operation center or SCS's power control center in Birmingham, Alabama. (Section 3)

SPT1 indicated that it would be managed by a team consisting of SPC's transmission, legal, state and local affairs, project finance, commercial optimization, environmental permitting and compliance, EPC project management, project development, operations and maintenance, and business origination departments. (QS-1)

SPT1 indicated that Southern Company has experience operating and maintaining more than 18,000 miles of high voltage transmission lines and more than 1,100 high voltage transmission substations. SPT1 indicated that, in addition, Southern Company has been involved in the development or operation of ten STATCOMs, SVCs, or synchronous condensers. (QS-4, S-3, S-4)

SPT1 indicated that it would utilize a management team that has significant experience operating and maintaining transmission facilities, including substation reactive support projects, in NERC regions across North America, including California. SPT1 indicated that this management team has experience establishing standards and procedures designed to comply with NERC standards. SPT1 provided an SCS operations and compliance organization chart. The chart indicated that there were compliance functions reporting up through various executives, the general counsel, and chief compliance officer for SCS. SPT1 indicated that this organization would be available to support SPT1 and SPC in operation and compliance for this facility.

SPT1 indicated that operation of the facility would be handled by either a third party or internally in SPC's remote operation center or Southern Company Transmission's power control center in Birmingham, Alabama. SPT1 indicated that both facilities are operated by qualified personnel who adhere to standard operating practices and have experience preparing and responding to emergency operating conditions. (O-1)

SPT1 provided resumes for its O&M team indicating many years of utility experience. (O-2)

SPT1 indicated that Southern Company Services, Inc. - Transmission (SCS-Trans) performs the functions of NERC Transmission Operator, Balancing Authority, and Reliability Coordinator for a large portion of the southeastern United States.

SPT1 indicated that Southern Company has been involved in various aspects of ten STATCOMs, SVCs, or synchronous condensers over the past several years. SPT1 indicated that the SCS operations and compliance teams have been involved with each of the ten projects listed. SPT1 indicated that SPC employees have all been involved in some aspects of the three SPC reactive support devices, including design, construction, integration, operating, and maintaining these facilities. (QS-4, S-3, S-4)

SPT1 indicated that, as required by NERC reliability standards, SCS-Trans's system operators performing the NERC reliability-related tasks of the Reliability Coordinator, Balancing Authority, and Transmission Operator are certified through the NERC system operator certification program. SPT1 indicated that certifications are maintained current through continuing education utilizing both internal training administered by SCS bulk power operations training staff and external training and workshops. (O-4)

SPT1 indicated that SCS-Trans's operator training program meets or exceeds the requirements of NERC Reliability Standard PER-003-2 and has been characterized by SERC auditors as best-in-class. (O-5)

SPT1 indicated that it intends to have the applicable NERC TO and TOP registrations in place prior to operation. (O-11)

SPT1 indicated that its proposal reflects self-performing both the TO and TOP functions. SPT1 indicated that it intends to engage PG&E or another already existing ISO PTO to potentially operate or maintain at least the switchyard portion of the project. SPT1 indicated that this seems a logical fit for PG&E given that four of its lines would terminate into the switchyard. SPT1 indicated that, regardless, only an entity that is well qualified with proven operating experience would be considered if such entity can provide the service reliably and with similar or lower costs. SPT1 indicated that any shared NERC obligations would be appropriately addressed in a CFR agreement. (O-12)

SPT1 indicated that SPC utilizes the Southern Company corporate internal compliance program, which is documented in an ethics and compliance framework document. SPT1 indicated that the internal compliance program is designed to meet or exceed the seven due-diligence elements of an effective compliance program defined in the Federal Sentencing Guidelines for Corporations enacted in 1991 and subsequent amendments.

SPT1 indicated that Southern Company's internal compliance program is reviewed periodically and approved by the Southern Company ethics and compliance council. SPT1 indicated that the internal compliance program is also widely disseminated to employees via the intra-company web. SPT1 indicated that regulatory responsibilities are identified and communicated to personnel responsible for executing the activities associated with the requirements. SPT1 indicated that annual NERC training specific to the business units is developed and delivered via live or web-based sessions. SPT1 indicated that compliance oversight is conducted at both the business unit and corporate levels, and all NERC requirements are subject to monitoring and testing according to the corporate NERC internal controls program.

SPT1 indicated that it does not anticipate that any temporary waivers under TCA Section 5.1.6 would be required. (O-13)

SPT1 indicated that Southern Company is collectively registered for eleven NERC functions in nine separate registrations. SPT1 indicated that functions performed include the NERC reliability functions of Balancing Authority, Reliability Coordinator, and Transmission Operator. SPT1 indicated that since 2007, Southern Company has participated in 26 audits involving six NERC regions encompassing both CIP and O&P standards. SPT1 indicated that O&P audit results generally resulted in no findings or minor findings resulting in recommendations and concerns.

SPT1 indicated that Southern Company has self-reported several possible NERC violations of O&P standards that resulted in enforcement action in the SERC and FRCC regions. SPT1 indicated that examples include violations of NERC reliability standards FAC-003, FAC-008, PRC-005, and VAR-002. SPT1 indicated that all of the issues were determined to pose minimal to moderate risk and were effectively mitigated. SPT1 indicated that none of the violations revealed systemic issues with Southern Company's internal compliance program.

SPT1 indicated that the amount of Southern Company transmission facilities subject to NERC compliance include:

- 18,350 miles of transmission line
- 1,150 transmission substations

(O-14)

SPT1 indicated that it would seek to divide obligations through a coordinated services agreement in line with the tasks being performed by SPT1 as the owner and operator of a reactive power compensation facility. SPT1 indicated that this would include communications, cyber system protections, applicable information sharing, emergency operating plans, equipment monitoring, and real-time operational requirements, as well as providing necessary data for the ISO to manage system models, transmission access, and other obligations related to the ISO system impacted by the facility. SPT1 indicated that upon review of existing agreements on the ISO website, it anticipates that a coordinated services agreement would be very similar to the agreement between ISO and Trans Bay Cable LLC. (O-15)

SPT1 indicated that given the expected configuration and scope of this equipment, SPC does not anticipate other functional registrations to be involved with the TOP obligations. SPT1 indicated that SPC would adhere to all applicable NERC standards under its TOP and TO registrations. (O-16)

SPT1 indicated that it would retain and utilize the appropriate data to assess its availability measures performance based upon forced outage records. SPT1 indicated that all forced outages would be documented, including the date, start time, end time, affected transmission facility, and the probable cause(s) if known, and saved for annual reporting purposes. SPT1 indicated that it would submit its availability measures performance to the ISO at a minimum on an annual basis. (O-17)

SPT1 indicated that it would leverage the same teams that are used to manage the Southern Company operating fleet of generation and transmission for the operations and maintenance of the facility and would comply with all ISO requirements. SPT1 indicated that this would include compliance with ISO tariffs, ISO protocols, and any other operating procedures. SPT1 indicated that it would follow all maintenance planning, forced outage reporting, and follow-up reporting requirements. (O-18)

SPT1 indicated that it would make available all resources, including local maintenance teams, to respond to and comply with emergency conditions. SPT1 indicated that its local maintenance teams would be located in northern California, with the contractor to be selected based on appropriate resources, experience, and capabilities operating in the ISO area and working with STATCOMs. SPT1 indicated that emergency operating procedures would be created and integrated with the ISO and system transmission operators to ensure proper coordination. SPT1 indicated that due to the limited scope of this facility, plans would place priority on the restoration and operation of the facility to work in conjunction with PG&E's and the ISO's system restoration plans. SPT1 indicated that the NERC TOP function for SPT1 would be monitored 24/7 and have the capability to quickly initiate a response to emergency conditions. SPT1 indicated that it expects to be able to contact and dispatch local maintenance teams to respond to emergency conditions within an hour of the emergency event.

SPT1 provided the Cactus Flats Wind generating station emergency operating plan and indicated that it was SPC's most recently approved emergency operating plan. SPT1 indicated that the emergency operating plan for the project should be similar in form and substance to this sample plan. (O-19)

SPT1 indicated that the project would not be subject to any encumbrance. (O-20)

3.10.19 Information Provided by Tenaska

Tenaska indicated that it has assembled and worked closely with a team of capable and experienced third-party contractors and consultants. Tenaska indicated that it has begun discussions with potential third-party suppliers and contract providers, including a leading operations and maintenance company.

Tenaska indicated that it has not chosen contractors to manage the execution, the construction, and the O&M of the project but has provided information for its proposed O&M service provider. Tenaska indicated that the project sponsor would use contractors selected through competitive solicitations to manage the execution, the construction, and the O&M of the project. Tenaska indicated that these third-party contractors would be managed by the project sponsor, which would draw on the resources of its corporate affiliates at Tenaska. (Section 3, QS-1, O-1)

Tenaska indicated that it currently manages and operates nearly 8,000 MW of power generation and associated interconnection equipment. For transmission-specific operations needs, Tenaska indicated that it intends to contract with an experienced third-party as its O&M service provider. (QS-4)

Tenaska provided information regarding five transmission line projects (above 200 kV) and seven substation projects for which it has direct experience with project operation. Of the five transmission line projects, two are in California and the remainder are in other parts of the U.S. Of the seven substation projects, three are in California and the remainder are in other parts of the U.S. (P-1)

Tenaska indicated that overall responsibility for the operations and maintenance services to be provided would lie with its proposed O&M service provider under a contractual relationship with the project sponsor. Tenaska indicated that its O&M service provider team would report to Tenaska asset management personnel. Tenaska indicated that operations responsibilities would be managed by its operations service provider, a subsidiary of its O&M service provider, through its president and 24/7 desk. Tenaska indicated that within its O&M service provider’s organization, the project manager would report to a senior operations director and be able to draw upon the organization’s extensive back office support team in the areas of regulatory compliance and maintenance and engineering support. (O-1)

Tenaska provided resumes for its proposed O&M service provider’s key personnel and described their responsibilities and reporting relationships. The resumes indicated many years of utility experience. (O-2)

Tenaska indicated that its assessment program is used to review its own compliance with its procedures. Tenaska indicated that this program requires that it review its program compliance on a tri-annual, rotating basis, at each of the facilities that it operates and maintains. Tenaska indicated that the assessment program also reviews the implementation of best practice notifications issued by its corporate operations and maintenance management team. Tenaska indicated that its proposed O&M service provider has a governance and compliance group for internal controls. Tenaska indicated that its O&M service provider has been developing a computer-based compliance management system that would be used to monitor and enforce compliance with both regulatory and its O&M service provider’s company standards. (O-3)

Tenaska indicated that because its proposed O&M service provider is expected to provide O&M staffing for this project, it provided information based on its O&M service provider's training and qualification programs. Tenaska indicated that its O&M service provider ensures that all its system operators have, and maintain, their NERC certifications at the Reliability Coordinator level. Tenaska indicated that its O&M service provider also has an in-house training and development manager who helps tracks certifications and continuing education credits. (O-4, O-5)

Tenaska indicated that it is currently a NERC-registered Generator Owner and Generator Operator in various NERC regions through North America, as well as a NERC-registered Transmission Owner for one 80+ mile transmission line. Tenaska indicated that as it relates specifically to the proposed project, Tenaska would become a registered Transmission Owner in WECC and would have a subcontractor register as a Transmission Operator. (O-11)

Tenaska indicated that its proposed O&M service provider would perform the TO services internally from the resources and expertise of its headquarters-based NERC department. Tenaska indicated that its O&M service provider would be contracted to register as and perform the TOP functions. (O-12)

Tenaska indicated that the PTO would not need to take exceptions to TCA Section 5.1.6.

Tenaska indicated that it has a complete NERC compliance program for the fleet of generation facilities that it owns and operates and has an excellent compliance track record. Tenaska indicated that it would provide general compliance oversight for the project, but, as noted above, Tenaska would contract with its O&M service provider to provide O&M services, which would include primary responsibility for managing NERC compliance. Tenaska indicated that its proposed O&M service provider, and its subsidiary operations service provider, have a robust NERC compliance program for the large fleet of generation, transmission, and balancing authority facilities that they manage. Tenaska indicated that its O&M service provider also provides comprehensive NERC compliance services to the power industry across all registered functions using the 20 personnel in its NERC department. Tenaska indicated that its operations service provider personnel are active members of various sharing groups, including the Northwest Power Pool and the Southwest Reserve Sharing Group. (O-13)

Tenaska indicated that its proposed O&M service provider is a leader in NERC reliability and CIP compliance with an in-house and highly experienced and proven team of more than 20 NERC professionals, including auditors, industry experts, and NERC and CIP reliability specialists. Tenaska indicated that its O&M service provider has provided services to more than 150 power generation facilities totaling tens of thousands of MW, including facilities for which its O&M service provider is registered with NERC as the Generator Operator or Transmission Operator.

Tenaska indicated that its proposed O&M service provider would develop the appropriate policies and procedures, maintain the proper documentation, and submit reports as required by NERC or the regional entity, in order to be compliant with applicable NERC reliability standards.

Tenaska indicated that its proposed O&M service provider has completed more than 100 audits of its registered facilities and supported more than 150 audits of other facilities since 2008. Tenaska indicated that its O&M service provider has not received a compliance penalty since 2010 and the last penalty paid by any of its clients was in 2013.

Tenaska provided sample NERC audit reports for its proposed O&M service provider and three other entities showing no findings for the requirements audited and no areas of concern.

Tenaska indicated that through its proposed O&M service provider's relationship with regional entities, along with its O&M service provider's culture of compliance and strong internal controls, should a violation occur, the penalties to its O&M service provider are expected to be significantly less or zero. (O-14)

Tenaska indicated that its proposed O&M service provider would provide technical leadership and program coordination in NERC reliability program compliance and would work in coordination with the project sponsor and ISO. Tenaska indicated that it would ensure its TOP subcontractor plans to enter into a CFR agreement with the ISO similar to the existing CFR agreements posted on the ISO website. Tenaska indicated that based on the currently available agreements, there would be no changes expected. (O-15)

Tenaska indicated that its operations service provider's interaction with PG&E, the neighboring TOP, would be limited to data exchanges through the ISO and phone calls in case of emergencies.

Tenaska did not identify the need for an interconnection agreement with PG&E. (O-16)

Tenaska indicated that its operations service provider would conduct all aspects of 24x7 transmission operations that would include a primary control center based in Texas and a backup control center. Tenaska indicated that its operations service provider has two remote data centers that are "hot-hot" to ensure no loss of data could occur. Tenaska indicated that all availability data required by TCA Appendix C Section 4.3 would be electronically submitted when possible and further communicated annually.

Tenaska indicated that its operations service provider would submit an annual report to the ISO within 90 days after the end of each calendar year describing the project's availability measures performance. Tenaska indicated that this annual report would be based on forced outage records, which would include the date, start time, end time, affected transmission facility, and problem cause. (O-17)

Tenaska indicated that its proposed O&M service provider would provide a comprehensive O&M solution for the project. Tenaska indicated that the uniquely valuable combination of its operations service provider's control center and decades of hands-on operations experience in critical 24x7 electric power facilities would provide a reliable platform for outsourced operations. Tenaska indicated that the depth of its compliance experience with NERC reliability and EHS standards differentiates its O&M service provider when it comes to operational risk management. Tenaska indicated that its proven approach for implementing O&M programs would ensure superior oversight over and optimal performance of the project. Tenaska indicated that its commercial approach to managing electric power projects was forged in the competitive independent power producer market, shaping within its O&M service provider a drive toward lean and effective O&M services.

Tenaska indicated that its proposed O&M service provider would:

- Operate the project safely and in compliance with all regulatory requirements and project agreements.
- Work closely with its operations service provider, which would utilize its 24/7 monitoring capabilities of the project and would coordinate ISO operating orders and switching actions with tagging and clearance practices that are accepted in the industry.
- Achieve high availability through diligent planning, work scheduling, preventative maintenance execution and being ready to respond and remediate unscheduled outages while operating the project to approved plans and budgets.
- Obtain approval from the ISO pursuant to the ISO Tariff before taking out of service and returning to service any facility, except in cases involving immediate hazard to the safety of personnel or the public or imminent damage to facilities.
- In the case of a forced outage, notify the ISO promptly.
- After a system emergency or forced outage, restore service of the transmission facilities under ISO's operational control as soon as possible and in the priority order determined by the ISO.
- Provide the ISO with a written report describing the circumstances and the reasons for any forced outage.
- Forecast and coordinate maintenance outage plans in accordance with Section 9 of the ISO Tariff.
- Coordinate maintenance outages with non-participating generators (as necessary), including exercising contractual rights to require maintenance by those generators in such manner as ISO approves or requests.
- Notify the ISO of any faults on the ISO controlled grid or any actual or anticipated forced outages as soon as aware of them.
- Take all steps necessary to prevent forced outages.
- Return to operation, as soon as possible, any facility under the ISO's operational control that is subject to a forced outage. (O-18)

Tenaska indicated that its proposed O&M service provider's emergency operating plans include emergency situations that may result in imminent or direct threats to public safety or threaten or impair its ability to provide reliable transmission service to its client. Tenaska listed emergency situations related to transmission lines as examples.

Tenaska indicated that a restoration plan program, which would include a plan specific to the project TOP area based on the characteristics of the project footprint, applicable NERC requirements, and ISO restoration program documentation guidance, would be followed.

Tenaska provided a sample emergency plan to be followed by its O&M service provider personnel to respond to a major facility fire.

Tenaska indicated that the project manager would work to have the project join a regional joint cooperation pool with neighboring utilities, and, once a member, the project manager would manage the operational relationship and be the point of contact with the pool.

Tenaska indicated that its proposed O&M service provider has O&M support staff located in northern California. Tenaska indicated that response time would be three to six hours for emergencies and 48 hours for non-emergencies.

Tenaska indicated that its proposed O&M service provider and Tenaska would endeavor to enter into a mutual support agreement with PG&E to reduce response times as necessary. (O-19)

Tenaska indicated that the project would not be subject to any encumbrance as defined in the TCA. (O-20)

3.10.20 Information Provided by TransCanyon

TransCanyon indicated that its team is composed of staffs of its affiliates and partners. The organization chart provided by TransCanyon summarized each individual's role and experience and included a seven-person operations and maintenance team comprised of personnel from TransCanyon's affiliate PacifiCorp and its STATCOM manufacturer and construction contractor, described above. (QS-1)

TransCanyon provided information regarding four transmission line projects (above 200 kV) outside of California and four substation projects outside of California where its parent companies, APS and BHE, have operating experience. TransCanyon indicated that it would rely on the experience of its team members and parent companies for this project. Three of the substation projects included reactive compensation or series capacitors. (P-1)

TransCanyon indicated that it has entered into an MOU with PacifiCorp regarding certain potential grid operations services that PacifiCorp may offer TransCanyon. TransCanyon indicated that its ability to use the services of PacifiCorp would be subject to regulatory approvals related to affiliate transaction rules, as described in Section 3.9.12 above. TransCanyon indicated that it believes that the above regulatory approvals can be obtained in the ordinary course similar to how NextEra obtained approval in the Suncrest SVC project CPUC proceeding (A.15-08-027). (Section 3, QS-1, O-1)

TransCanyon indicated that the MOU sets out the conditions under which PacifiCorp may offer, and TransCanyon may utilize, the grid operations, asset management, and corporate compliance organization of PacifiCorp to provide operations and facilitate maintenance services for the project. TransCanyon provided a copy of the MOU.

TransCanyon indicated that the individual at PacifiCorp who would be responsible for providing these services would be the Vice President of Transmission Operations and Maintenance and that PacifiCorp's team would be composed of three departments, transmission operations, asset management, and compliance.

TransCanyon indicated that PacifiCorp's grid operations support team consists of engineering, outage planning, and advanced applications. TransCanyon indicated that grid operations also relies on dedicated compliance experts who formally report through PacifiCorp's compliance department but provide dedicated support to operations.

TransCanyon indicated that PacifiCorp transmission system operations consists of one primary control center - the system power control center located in Portland, Oregon to meet its functional obligations with regard to the reliable operations of the bulk electric system. TransCanyon indicated that the system power control center is a fully functional control center with a redundant, fully functional control center in Salt Lake City. (O-1)

TransCanyon provided resumes for key PacifiCorp operations management positions indicating many years of experience. (O-2)

TransCanyon indicated that PacifiCorp has extensive experience operating and maintaining a large and complex transmission system. TransCanyon indicated that the company serves six states and has operated EHV transmission lines since the early 1970s. (O-3)

TransCanyon indicated that all transmission operators at PacifiCorp hold current NERC reliability coordinator certifications, which have been granted based on comprehensive knowledge assessments of these personnel by NERC. TransCanyon indicated that in addition, the PacifiCorp system operations training organization has been designated a NERC approved provider of continuing training for certified transmission operators. TransCanyon indicated that as part of the PacifiCorp EMS system, a state-of-the-art operator training simulator, which represents the complete model of the PacifiCorp system and surrounding transmission system, is utilized for training operators involved in real-time system operations. (O-4)

TransCanyon indicated that PacifiCorp's system operations uses a robust operator training program, sophisticated operator tools, and dedicated 24/7 support from the system operations engineering team. TransCanyon indicated that PacifiCorp's system operations training focuses on achieving results for the organization consistent with NERC reliability standards. TransCanyon indicated that PacifiCorp operating personnel are required to demonstrate the knowledge and competencies needed to apply these standards, procedures, and requirements to normal, emergency, and restoration conditions.

TransCanyon indicated that PacifiCorp has a dedicated training coordinator who works full time on program development and delivery and has created a dedicated training week that operators attend once every six months. TransCanyon provided a copy of PacifiCorp's system operator training manual. TransCanyon indicated that PacifiCorp has made a substantial investment in operator tools to provide greater situational awareness, real-time contingency analysis, geo-relative visualization, and enhanced EMS functionality. (O-5)

TransCanyon indicated that it intends to register with NERC as the TO, TOP, and Transmission Planner for the project, subject to applicable coordinated functional registration with the ISO. (O-11)

TransCanyon indicated that it has chosen to contract with PacifiCorp to provide the NERC Transmission Operator and Transmission Owner functions based on PacifiCorp's operational experience and expertise in performing both services. TransCanyon indicated that PacifiCorp is currently registered and has the capabilities to perform the NERC functions of Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Load-Serving Entity, Planning Authority, Purchasing-Selling Entity, Resource Planner, Transmission Operator, and Transmission Owner.

TransCanyon indicated that it has reviewed PacifiCorp's operations and maintenance processes and programs to ensure the requirements of the NERC standards are met. TransCanyon indicated that it has also evaluated PacifiCorp's internal compliance program as well as the controls PacifiCorp has in place to ensure ongoing compliance with the NERC standard requirements. TransCanyon indicated that it and PacifiCorp would continually review the programs in place that assure ongoing compliance. (O-12)

TransCanyon indicated that it plans to develop processes in coordination with PacifiCorp to continually review the programs and controls used by PacifiCorp to ensure compliance with applicable reliability standards. TransCanyon indicated that it would assure seamless integration with PacifiCorp systems already subject to and in compliance with NERC reliability standards.

TransCanyon indicated that it would have access to PacifiCorp personnel to provide oversight of and executive level decision-making for ongoing compliance by PacifiCorp and TransCanyon with FERC-approved NERC reliability standards and FERC-approved WECC reliability standards.

TransCanyon indicated that at this time, TransCanyon is unaware of any potential temporary waivers under TCA Section 5.1.6 that may be required. (O-13)

TransCanyon indicated that it is a new reliability entity and does not have a compliance history.

TransCanyon indicated that PacifiCorp owns and operates one of the largest privately held transmission systems in the U.S., and takes its role as a reliability entity very seriously.

TransCanyon indicated that PacifiCorp operates and maintains over 12,000 miles of transmission facilities (approximate data) and 361 transmission substations that are subject to NERC compliance.

TransCanyon indicated that PacifiCorp has put the necessary policies, procedures, and practices in place to ensure on-going and continued compliance with all applicable NERC reliability standards. TransCanyon indicated that PacifiCorp has an independent corporate compliance organization that includes a compliance director and 15 compliance analysts, responsible for overseeing and validating compliance.

TransCanyon provided a list of violations from 2014 to present, which included three violations, two of which were self-reported. (O-14)

TransCanyon indicated that it is comfortable with the Participating Transmission Owner Reliability Standards Agreement executed between TBC and the ISO and would be willing to enter into a similar agreement or negotiate different terms if preferred by the ISO. (O-15)

TransCanyon provided a list of applicable agreements, including an interconnection agreement and an operational agreement. TransCanyon indicated that it would comply with the ISO Tariff provisions for planning authority and that it would develop a wire-to-wire interconnection process that would comply with all aspects of the ISO Tariff and the TCA. TransCanyon indicated that the ISO would be the balancing authority for the project and that TransCanyon would comply with the ISO Tariff and TCA requirements to facilitate the ISO's balancing authority responsibilities. TransCanyon indicated that it is a WestConnect member and coordinates with other NERC Transmission Planners through the ISO transmission planning process and WestConnect. (O-16)

TransCanyon indicated that PacifiCorp's EMS and SCADA systems are designed to meet or exceed all NERC availability, reliability, security, and performance standards and metrics.

TransCanyon indicated that PacifiCorp manages its dual balancing authority areas, dual time zone transmission/distribution/generation system through two control centers. TransCanyon indicated that the control centers are located 760 miles apart, with one in Portland, Oregon and the other in Salt Lake City, Utah. TransCanyon indicated that each control center has a full assortment of redundant server pairs that would fall over automatically upon specific conditions. TransCanyon indicated that the EMS and SCADA system, including state estimation and contingency analysis, runs as primary from one site, with the other site receiving full real-time data replication and maintained in the warm standby mode.

TransCanyon indicated that PacifiCorp maintains and tests an alternate control center located in Portland. TransCanyon indicated that additionally there is a secondary transmission alternate control center located within the Salt Lake City building. TransCanyon provided a copy of procedures for activating the back-up controls centers in its grid operations business recovery plan.

TransCanyon indicated that following PacifiCorp's data storage policy, all data points (values/status) are archived and maintained for seven years. TransCanyon indicated that additionally all system activity performed by operations and support personnel, as well as alarms and events, are captured and stored for a seven-year period. (O-17)

TransCanyon indicated that PacifiCorp has repeatedly demonstrated its ability to comply at a minimum with the activities and responsibilities required by TCA Section 6.1, 6.3, and 7.

TransCanyon indicated that PacifiCorp's grid operations department includes an operations planning group of two dedicated planners that performs extensive studies, including current and next-day analysis studies, and any required mitigation plans that may be required based on scheduled or emergency outage conditions.

TransCanyon indicated that PacifiCorp would inspect, maintain, repair, replace, and maintain the rating and technical performance of its facilities in accordance with reliability criteria and performance standards established by the ISO.

TransCanyon indicated that the PacifiCorp system operations organization:

- Plans and coordinates maintenance activities both internally and externally with neighboring utilities
- Coordinates planned or emergency outages with impacted generators
- Notifies appropriate parties of forced outages in real-time
- Assures that forced outages would not be prolonged unnecessarily.

TransCanyon indicated that PacifiCorp would dispatch its construction contractor for emergency response and would facilitate maintenance outages, clearances and tagging for the construction contractor or its STATCOM manufacturer to perform emergency response, monthly equipment inspections, and scheduled preventative maintenance activities at the project. (O-18)

TransCanyon indicated that PacifiCorp has extensive capability and experience to comply with the emergency management and emergency reporting obligations described in TCA Sections 9.2 and 9.3, respectively. TransCanyon indicated that PacifiCorp has an emergency manager for each of the two business units within PacifiCorp and another one associated with the generation side of the business. TransCanyon indicated that these individuals work closely to ensure that the emergency procedures are developed and drills are executed to ensure their described capabilities. TransCanyon indicated that these emergency managers coordinate with external entities as well as community leaders and first responders to ensure safe and reliable operations in emergency situations.

TransCanyon provided a copy of PacifiCorp's system restoration plan.

TransCanyon indicated that it has entered into maintenance service agreements with its proposed STATCOM manufacturer for scheduled preventative maintenance services and with its proposed construction contractor, described above, for monthly inspection and emergency response services for the project. TransCanyon indicated that PacifiCorp would facilitate the work activities specified in these agreements on behalf of TransCanyon. TransCanyon indicated that its STATCOM manufacturer has committed to a four-hour response time for emergency assistance. TransCanyon indicated that the PacifiCorp operator would direct the STATCOM manufacturer's personnel regarding the necessary steps to isolate the equipment, establish clearances, and develop plans to expedite repair or replacement of the equipment. TransCanyon indicated that the manufacturer's technical personnel would be available 24 hours a day, 365 days a year for technical support if necessary and would mobilize to the project site as soon as possible if required. TransCanyon indicated that the manufacturer has engineers at offices in northern and southern California.

TransCanyon indicated that its personnel would provide any required after-the-fact emergency reporting. (O-19)

TransCanyon indicated that the project, as proposed, would not be subject to any encumbrances and that the entire project would be placed under the operational control of the ISO through the TCA. (O-20)

3.10.21 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 standards. 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 HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon with regard to 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 considers all six project sponsors and their proposed teams to have the basic capability to adhere to standardized maintenance practices for their twelve proposals. However, the information provided by the project sponsors indicated that some of the project sponsors have more well-established organizations and processes regarding the development of and adherence to maintenance practices for EHV transmission facilities and dynamic reactive support devices than other project sponsors. Also, the scope of their prior maintenance practices varied.

The proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, indicated that they would be supported by well-established maintenance organizations and processes for the development of and adherence to maintenance practices for EHV transmission facilities and reactive support devices, including 130 MVAr of STATCOM, and further strengthened as a result of HWT's acquisition of the Trans Bay Cable project, which is equipped with converter station equipment that is similar to a STATCOM. HWT's proposals also indicated that HWT has submitted processes for dealing with the ISO and the requirements of the TCA regarding maintenance practices.

SPT1's proposal indicated that it would be supported by well-established maintenance organizations and processes. SPT1 affiliates have experience maintaining extensive EHV transmission facilities, including STATCOM and reactive support devices, but SPT1 and its affiliates have no experience under the ISO's TCA maintenance requirements.

TransCanyon's proposal indicated that TransCanyon has existing organizations and processes in place that demonstrate the capability to develop and adhere to standardized maintenance practices for EHV transmission facilities and reactive support devices but has no formal processes for dealing with the ISO and its TCA maintenance requirements. TransCanyon's proposal also indicated that although TransCanyon's proposed team has relevant maintenance organizations and processes, TransCanyon's proposed use of certain affiliates is subject to regulatory approvals.

LSPGC's proposal indicated that it has existing organizations and processes for developing and adhering to standardized maintenance practices for EHV transmission facilities, but less experience with maintenance practices for reactive support devices than HWT, for its proposals 1, 2, 3, 6, 7, and 8, SPT1, or TransCanyon. Also, it has no formal processes for dealing with the ISO and its TCA maintenance requirements.

Tenaska's proposal indicated that its O&M service provider would be responsible for developing and implementing maintenance practices for the project. Tenaska provided information regarding its proposed O&M service provider's practices, but it also indicated that it hasn't actually selected that firm for the project and intends to solicit bids for performance of project maintenance. Tenaska's proposal indicated that it has experience maintaining transmission lines in California, but the scope of the EHV transmission facilities maintained by its O&M maintenance team is less extensive than the O&M teams of HWT, LSPGC, SPT1, and TransCanyon. Tenaska's proposal also has no formal processes for dealing with the ISO and its TCA maintenance requirements.

SEGG's proposal indicated that its O&M contractor would be responsible for developing and implementing maintenance practices for the project. SEGG's proposal indicated that the scope of the EHV transmission facilities maintained by its O&M maintenance team is less extensive than the other project sponsors' teams. A review of SEGG's proposal indicated that its maintenance practices are less developed and formalized than those of the other project sponsors. Also, it has no formal processes for dealing with the ISO and its TCA maintenance requirements.

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 there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, and that they are slightly better than the proposals of LSPGC, SEGG, with regard to its proposals 1 and 2, SPT1, Tenaska, and TransCanyon with regard to this component of the factor. The ISO has also determined that SPT1's proposal is slightly better than TransCanyon's proposal, which is slightly better than LSPGC's proposal, which is slightly better than Tenaska's proposal, which is slightly better than SEGG's proposals 1 and 2, between which there is no material difference, with regard to this component. The ISO notes that all of the project sponsors are qualified and capable of maintaining transmission facilities associated with this project.

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 considers all six project sponsors and their proposed teams to have the basic capability to adhere to standardized operating practices for their twelve proposals. However, the information provided by the project sponsors indicated that some the project sponsors have more well-established organizations and processes related to the operation of EHV transmission facilities and dynamic reactive support devices than other project sponsors. Each project sponsor's proposed O&M organization includes the necessary operations, maintenance, and compliance functions. All of the project sponsors have transmission facilities subject to NERC compliance, and each provided some information on compliance audit results. All project sponsors described emergency operations processes.

HWT, through its affiliate TBC, demonstrated experience operating a transmission facility in accordance with ISO operating requirements. HWT, SPT1, and TransCanyon affiliates have experience operating extensive transmission facilities and dynamic reactive support devices. SPT1's affiliates have experience operating STATCOMs; however, SPT1's proposal indicated that it intends to engage PG&E or another already existing ISO PTO potentially to operate or maintain at least the switchyard portion of the project. Tenaska's proposal indicated that it has experience with the operation of transmission facilities in California and provided information regarding its proposed O&M service provider's operating practices for the large fleet of generation, transmission, and balancing authority facilities that it and its subsidiary for project operations manage, but Tenaska also indicated that it hasn't actually selected that firm for the project and intends to solicit bids for performance of project operations. SEGG's proposal indicated that its contractor for the transmission operating function operates transmission lines ranging from 0.5 miles of 500 kV lines to approximately 22 miles of 138 kV lines that are subject to NERC compliance requirements. SEGG was less specific with respect to response times to operational or other emergencies for this reliability project than the other project sponsors. LSPGC's proposal indicates that its proposed operator operates more EHV transmission facilities subject to NERC and WECC compliance than SEGG's operator.

TransCanyon's proposal also indicated that although TransCanyon's proposed team has relevant operations organizations and processes, TransCanyon's proposed use of certain affiliates is subject to regulatory approvals.

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 there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, and that they are slightly better than the proposals of the other project sponsors. The ISO has determined that SPT1's proposal is slightly better than TransCanyon's proposal, which is slightly better than LSPGC's proposal, which is slightly better than SEGG's proposals 1 and 2, and Tenaska's proposal, among which there is no material difference, with regard to this component of the factor.

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.

With regard to the first component of this factor (demonstrated capability to adhere to standardized construction practices), the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon with regard to this component of the factor.

With regard to the second component of this factor (demonstrated capability to adhere to standardized maintenance practices), the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, and that they are slightly better than SPT1's proposal, which is slightly better than TransCanyon's proposal, which is slightly better than LSPGC's proposal, which is slightly better than Tenaska's proposal, which is slightly better than SEGG's proposals 1 and 2, between which there is no material difference, with regard to this component of the factor.

With regard to the third component of this factor (demonstrated capability to adhere to standardized operating practices), the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, and that they are slightly better than SPT1's proposal, which is slightly better than TransCanyon's proposal, which is slightly better than LSPGC's proposal, which is slightly better than SEGG's proposals 1 and 2 and Tenaska's proposal, among which there is no material difference, with regard to this component of the factor.

Based on the foregoing comparisons for the components of this factor, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8; and they are slightly better than SPT1's proposal, which is slightly better than TransCanyon's proposal, which is slightly better than LSPGC's proposal, which is slightly better than Tenaska's proposal, which is slightly better than SEGG's proposals 1 and 2, between which there is no material difference, with regard to this factor overall.

3.11 Selection Factor 24.5.4(i): Ability to Assume Liability for Major Losses

(Section 3 - General Project Information , QS-1, QS-2, QS-4, P-2, F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8, F-9, F-10, F-11, F-12, F-13, F-14, O-21)

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 Information Provided by HWT for Proposals 1, 2, 3, 6, 7, and 8

HWT indicated that it would fund unexpected repairs by relying on its internal financial resources as well as its NEECH debt facility. HWT indicated that it would also have access to additional equity funding and additional credit facilities backed by NextEra to finance unexpected repairs. (F-13)

HWT indicated that NextEra, and/or its affiliated, subsidiary, and associated companies and/or corporations, which would include HWT, maintains and would maintain a property all-risk insurance program that would cover the facility from "all risks" of direct physical loss or damage, including, but not limited to: mechanical and electrical breakdown, wildfire, flood, earthquake, wind storm, and terrorism. HWT indicated that 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 would include the entire extent of failure of project facilities during the operation of the project. (P-2, F-13)

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, HWT indicated that the project design includes a fully installed spare 500 kV transformer, a complete spare cable for each circuit, and a five-year project warranty. HWT indicated that it would hold selected strategic spares and would also have access to its affiliate company-wide spares sharing program, specifically FPL 500 kV spares and strategic support of equipment suppliers. (O-21)

3.11.2 Information Provided by LSPGC

LSPGC indicated that, to the extent not covered by insurance, it would maintain cash operating reserves and a line of credit to cover unexpected capital replacements. LSPGC provided an example of LS Power's funding of increased costs due to equipment damage from a tornado, which was funded at the time by a combination of retained earnings and a self-insurance reserve and was reimbursed in substantial part by insurance proceeds. (F-13)

LSPGC provided a list of the types of insurance that it plans to maintain, along with the coverage amounts. LSPGC indicated that it would carry builders all-risk insurance during the construction period, which would cover the project on an "all risk basis" on a completed value form inclusive of earthquake, flood, windstorm, collapse, sinkhole, subsidence, testing, commissioning, riot, and civil commotion coverage, on a no coinsurance basis. LSPGC indicated that it would carry property all risk insurance throughout the operational life of the project, with policy limits and sub-limits that are appropriate for the risks, commercially available, and approved by the project lenders, which is planned to be full replacement value of the project based upon customary and currently available coverage. (P-2)

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, LSPGC provided a spare parts list for the project that included items in the following categories: (S-1)

- Multi-modular converter STATCOM valve
- Control panels
- Protection panels
- Cooling system
- Medium voltage equipment
- Low voltage equipment
- Spare transformer

3.11.3 Information Provided by SEGG for Proposals 1 and 2

SEGG indicated that the project sponsor would have sufficient access to financing to cover the project cost and potential cost overruns. SEGG indicated that its team has successfully dealt with equipment failures at prior projects. (F-13)

SEGG provided a list of types of insurance that it plans to maintain, along with the coverage amounts. SEGG indicated that the project would maintain all-risk builders risk and operational coverages, subject to industry standard exclusions and deductibles for the replacement cost of the plant. SEGG indicated that the entire project would be covered under these policies subject to industry standard sub-limits for the perils of earthquake and flood, as well as a sub-limit for the transmission line once the project has achieved substantial completion. (P-2)

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, SEGG indicated that a spare 3-phase unit, common for both -/+ 250 MVAr STATCOM or SVC blocks, for its proposal 1 or 2, respectively, is included in the design to allow switching over to the spare transformer in case of failure on either of the two main transformers. SEGG also indicated that its equipment supplier would supply a set of recommended spare parts that would cover the expected lifetime of the installation. (QS-4, QP-2, O-21)

3.11.4 Information Provided by SPT1

SPT1 indicated that it would finance unexpected repairs using a combination of operating cash flows from the project, insurance proceeds, if any, and capital contributions from the parent. SPT1 also indicated that SPC has owned, operated, and maintained a large generating fleet, including associated transmission lines and substations, for over a decade and has quickly responded to any equipment failures to restore service as quickly as possible. SPT1 indicated that these failures include two large generator step-up transformer failures that SPC was able to replace with shared Southern Company spares that were in stock and quickly replace the spares due to Southern Company's strong relationships, reserved production slots, etc. with multiple suppliers. SPT1 indicated that funding for these repairs was handled as described above. (F-13)

SPT1 provide a list of the types of insurance that would be managed by it or its general contractor during the construction stage and upon substantial completion. SPT1 indicated that during the construction period, the property being constructed would be insured by builder's risk insurance, and would be managed by either SPC or the general contractor until substantial completion is achieved. SPT1 indicated that the builder's risk insurance would include replacement cost coverage for the project while under construction and would typically include a delay in startup components. SPT1 indicated that once substantial completion is achieved, the property would be moved to SPC's operational property insurance, which covers all of SPC's facilities and property at a replacement cost value. (P-2)

SPT1 indicated that from a practical perspective, the project would have key spares on site including a spare main power transformer and modules for the reactive support device itself, so it does not anticipate that any unexpected repairs would require significant financial obligations. (F-13) SPT1 provided a list of proposed spare parts that are essential spares for use in the commissioning process and for maintenance during the base warranty period from its primary equipment manufacturer and EPC firm. SPT1's proposal also includes a spare step-up transformer shared by the two STATCOM blocks. (O-21) SPT1 indicated that Southern Company is an industry leader in storm restoration and in swiftly handling unexpected repairs, such as power transformer and major generation equipment failures, and that with decades of experience Southern Company has developed exceptional engineering, construction, maintenance, and logistical resources along with a large supply chain and spare equipment network to quickly and efficiently meet its customers' needs. (F-13)

3.11.5 <u>Information Provided by Tenaska</u>

Tenaska indicated that it and its affiliates have a history of maintaining available working capital to address unexpected repairs or replacements, which has included keeping cash on hand within the project, putting working capital facilities with lenders in place within the project, or some combination of both. Tenaska indicated that its projects have experienced several unexpected maintenance events over the past 30 years, involving turbines, transmission lines, etc., but that its projects have always made scheduled debt payments. (F-13)

Tenaska provided a list of the types of insurance that it would carry or cause its subcontractors and operator to carry during the construction and operational phases of the project. Tenaska indicated that the builder's risk policy during the project's construction phase would be provided on an "all risks" basis, subject to certain exclusions that are customary for this type of coverage. Tenaska also stated that the project's property and business interruption coverage during the operational phase would be written on an "all risk" form and that the property coverage limits would be based on the full replacement cost value of the project during the construction and operational phase. (P-2)

Tenaska stated that the project would include installed spares for STATCOM key equipment, such as transformers, Insulated Gate Bipolar Transistor sub-modules, cooling pumps, cooler, cooler fans, battery system, and battery chargers. In addition, Tenaska indicated that it would enter into a long-term maintenance contract with an appropriate maintenance contractor for the STATCOM equipment that would include equipment and spares, such as breakers, switches, and relays, and labor. Tenaska's proposal also includes a spare step-up transformer shared by the two STATCOM blocks. (O-21)

3.11.6 <u>Information Provided by TransCanyon</u>

TransCanyon indicated that it would have the ability to fund major unanticipated repairs from its own cash flow and, if necessary, from the revolving credit facilities maintained by its parent companies. (F-13)

TransCanyon listed all the types of insurance, including all risk builders risk, that its proposed EPC contractor and STATCOM manufacturer would carry. TransCanyon indicated that the insurance carried by the EPC contractor and STATCOM manufacturer would be used to cover the project during construction phase. TransCanyon indicated that once the project is in service, it would be covered by property insurance for the replacement cost value. TransCanyon indicated that the property insurance would cover all risks of physical loss or damage to operating equipment *(i.e.*, fire, earthquake, flood, theft, boiler and machinery breakdown, turbine generator breakdown). (P-2)

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, TransCanyon indicated that the system is designed to have a redundancy available for transformer and that one transformer would be readily available at all times. TransCanyon indicated that its proposal includes all strategic spares of the system components that have long lead deliveries from its STATCOM manufacturer and would maintain the spare inventory for the project on site to minimize down time resulting from equipment failure. TransCanyon indicated that it would procure an extended care package from its STATCOM manufacturer that would include spare equipment management advisory support. TransCanyon indicated that the spare parts list would be updated based in part on reliability, availability, and lead time. (O-21)

TransCanyon's proposal also includes one spare three-phase 500/40 kV power transformer common to both STATCOM blocks. (S-9)

3.11.7 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.

Financial Resources

As discussed above and in Section 3.7 of this report, the financial resources of the project sponsors vary, and their proposals vary as to how they would finance emergency repairs. Nevertheless, the ISO has determined that all six project sponsors have the financial resources to finance or otherwise assume liability for major losses resulting from failure of facilities for their twelve proposals.

Insurance

The ISO has determined that all six project sponsors have identified comparable insurance coverage for their twelve proposals, including coverage during the operation of the project up to replacement value.

Mitigation of Equipment Failures

All six project sponsors identified reasonable approaches to maintaining spare parts for use in the event of a major equipment failure. One of the largest potential failures for the project from a financial risk perspective would be a catastrophic failure of 500 kV substation transformer. There would be a significant capital expenditure to replace the failed transformer, as well as a reliability risk to the system until a replacement transformer could be placed into service. All project sponsors included a spare transformer as part of their proposals. All proposals also included a set of spare parts, such as Insulated Gas Bipolar Transistor valves and cooling system equipment in addition to the spare transformer.

The ISO has concluded that all six project sponsors have sufficient financial resources, insurance coverage, and operational arrangements to make necessary repairs and return the facilities to service in a reasonable period of time for their twelve proposals. 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 project sponsors for their twelve proposals with regard to this factor.

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 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) 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 four project sponsors provided binding capital cost containment proposals for their ten 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 binding cost containment measures, the ISO evaluated each project sponsor's proposal regarding the following 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

(Section 1 – Introduction, Section 3 - General Project Information, QS-1, QS-4, P-2, P-3, P-4, P-6, P-7, Attachment P-7.a, ISO Application Workbook)

3.12.1 Information Provided by HWT for Proposal 1

Cost Containment

HWT indicated that it is offering robust binding cost containment for the project, including a firm project cost cap and cap on return on equity with very narrow exclusions.

Specifically, HWT indicated that it is offering the following cost containment measures, which are also reflected in its project financial model:

- Overall project cost cap, with specified exclusions.
- Cap on the project's annual O&M and administrative and general (A&G) costs for a specified period of time.
- Cap on the project return on equity for the life of the project.
- Cap on the equity percentage for a specified period of time.
- Cap on the project's annual revenue requirement for a specified period of time.
- Financial penalty for failure to meet schedule.

(ISO Application Workbook)

HWT indicated that for its proposal 1 it is constructing the project in the configuration of alternative 1 of the ISO Functional Specifications.

HWT indicated that it estimates PG&E's tap lines will range from 950 feet to 1,250 feet.

Cost Containment Performance for Past Projects

HWT provided an extensive list of project experience regarding its performance regarding project budget. HWT provided budget information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project. HWT's list included 72 projects along with their associated statistics.

HWT indicated that for 26 of the projects actual cost exceeded the target cost but that of those 26 only five exceeded the target amount by more than 10% and that many of these projects were relatively small projects of less than $20 million. HWT indicated that many projects came in under budget. (P-3)

Project Management Capabilities

HWT indicated that it has assembled a team of accomplished professionals for the project who have an average of more than 15 years building high voltage transmission projects. HWT indicated that the project schedule reflects extensive project design and evaluation conducted for the project and includes route and site evaluation, regulatory permitting, land acquisition, engineering and design, land surveying, material procurement, construction, and commissioning and energization activities. (Executive Summary)

HWT indicated that it has a project management team of experienced professionals and subject matter experts for its core project team and would draw upon the extensive resources of its affiliates for the project execution. HWT indicated it would apply to its execution of the project the same proven project management approach NextEra successfully employed for the projects listed in its proposal and discussed above. (P-4)

HWT indicated that its project management team would actively manage all aspects of the project and that the project management team would provide a single point of accountability for day-to-day activities, oversee all project work stream leads and resources, and be responsible for reporting project progress to senior management. HWT indicated that the project management team would ensure consistency in the project goals and direction and track overall project progress and ensure resources are available to keep the project on budget and on schedule. (P-4)

HWT provided a detailed list of project management process steps and actions HWT would take during its development and construction of the project, based on the model used by other NextEra companies. HWT indicated the first and most important step in managing project execution and risk is a thorough collection, understanding, and documentation of the project scope and that this scope includes the project's specifications, milestones, necessary approvals and permits, and other requirements. HWT provided the details of the project that would be incorporated into the project scope. (P-4)

HWT indicated it would use technology platforms such as SharePoint and Unifier to facilitate the exchange of project information and communication by team members and that these platforms would be accessible by all internal and external team members. HWT indicated that its team would draw upon NextEra's matrixed organization of shared resources and contractors for project execution. (P-4)

HWT indicated that the project controls manager, under the finance lead, would assign a schedule and cost engineer to the project. HWT indicated that, with support of its engineers, contractors, and environmental consultant, HWT would coordinate and conduct focused workshops to detail all permitting, pre-construction compliance tasks, environmental restrictions, construction clearance limitation, engineering, procurement, and construction activities, as well as their dependencies. HWT indicated that it would integrate schedules from all contractors and participating entities into the master schedule and would schedule and track all phases of the project with the Primavera software. (P-4)

HWT indicated that when schedule and variances are identified, the HWT project management team would request a recovery plan from the project entity causing the variance and request that the recovery plan explain the root cause of the variance as well as mitigation to recover the baseline schedule. HWT indicated that the project management team would evaluate the recovery plan for impacts to dependent activities with consideration to available project float. HWT indicated that, if the schedule baseline cannot be recovered, the situation would be escalated, and the project management team would review the impacts and effects of a new baseline schedule update. (P-4)

HWT indicated that weekly schedule meetings with all participants would be held throughout the development of the project to update the schedule, review the two-week and four-week look ahead, and address critical path items. HWT indicated that any slip in the schedule would require the participating engineer, consultant, or contractor to develop a mitigation plan to get back on schedule. (P-4)

Project Risks and Mitigation of Risks

HWT indicated that it takes a holistic approach to risk management. HWT indicated that its evaluation of risk includes safety, environmental, technical, schedule, and cost. HWT indicated that the project management team would develop a risk mitigation strategy that fully quantifies and addresses the overall project risk and that of special emphasis would be the early identification of risks and the facilitation of proactive and efficient mitigation through design, process, data, resources, or sequencing. (P-4)

HWT indicated that during project scoping HWT identified and analyzed all aspects of the project, including but not limited to environmental permitting, regulatory approvals, land requirements, engineering and design specifications, major equipment and construction activities, and operation and maintenance activities, which enabled HWT to develop a detailed project schedule and budget, which eliminates a significant portion of project uncertainty. HWT provided its current risk and issues log for the project, which identifies major risks and obstacles to successful project completion on schedule and within budget. This log lists numerous risks considered by HWT. In the log, HWT has identified the specific risk, 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 planned or potential mitigation. (P-7) HWT indicated that throughout project planning, development, and construction, the risk and issues log is updated and the status of the risk and implementation of mitigations is tracked. (P-4)

Regarding HWT's ability to work on multiple projects simultaneously, HWT stated that HWT and its affiliates have sufficient financial, technical, and human resources to successfully work on and deliver multiple projects at the same time. (P-7)

HWT indicated it has the experience and resources to effectively manage risks associated with cost guaranties. HWT indicated the Suncrest SVC project is an example of HWT's commitment to cost containment because during permitting HWT agreed to underground a one-mile interconnection line and absorb the cost within its existing cost cap. HWT indicated that it did not seek relief from its cost cap for the undergrounding even though it was eligible for such relief. (P-7)

3.12.2 Information Provided by HWT for Proposal 2

Cost Containment

HWT indicated that it is offering robust binding cost containment for the project, including a firm project cost cap and cap on return on equity with very narrow exclusions. Specifically, HWT indicated that it is offering the following cost containment measures, which are also reflected in its project financial model:

- Overall project cost cap, with specified exclusions.
- Cap on the project's annual O&M and A&G costs for a specified period of time.
- Cap on the project return on equity for the life of the project.
- Cap on the equity percentage for a specified period of time.
- Cap on the project's annual revenue requirement for a specified period of time.
- Financial penalty for failure to meet schedule.

(ISO Application Workbook)

HWT indicated that for its proposal 2 it is constructing the project in the configuration of alternative 1 of the ISO Functional Specifications.

HWT indicated that it estimates PG&E's tap lines will range from 950 feet to 1,250 feet.

Cost Containment Performance for Past Projects

HWT provided the same information regarding cost containment performance for past projects for its proposal 2 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 2.

Project Management Capabilities

HWT provided the same information regarding its project management capabilities for its proposal 2 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 2.

Project Risks and Mitigation of Risks

HWT provided the same information regarding project risks and mitigation of risks for its proposal 2 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 2.

3.12.3 Information Provided by HWT for Proposal 3

Cost Containment

HWT indicated that it is offering robust binding cost containment for the project, including a firm project cost cap and cap on return on equity with very narrow exclusions. Specifically, HWT indicated that it is offering the following cost containment measures, which are also reflected in its project financial model:

- Overall project cost cap, with specified exclusions.
- Cap on the project's annual O&M and A&G costs for a specified period of time.
- Cap on the project return on equity for the life of the project.
- Cap on the equity percentage for a specified period of time.
- Cap on the project's annual revenue requirement for a specified period of time.
- Financial penalty for failure to meet schedule.

(ISO Application Workbook)

HWT indicated that for its proposal 3 it is constructing the project in the configuration of alternative 1 in the ISO Functional Specifications.

HWT indicated that it estimates PG&E's tap lines will range from 950 feet to 1,250 feet.

Cost Containment Performance for Past Projects

HWT provided the same information regarding cost containment performance for past projects for its proposal 3 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 3.

Project Management Capabilities

HWT provided the same information regarding its project management capabilities for its proposal 3 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 3.

Project Risks and Mitigation of Risks

HWT provided the same information regarding project risks and mitigation of risks for its proposal 3 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 3.

3.12.4 Information Provided by HWT for Proposal 6

Cost Containment

HWT indicated that it is offering robust binding cost containment for the project, including a firm project cost cap and cap on return on equity with very narrow exclusions. Specifically, HWT indicated that it is offering the following cost containment measures, which are also reflected in its project financial model:

- Overall project cost cap, with specified exclusions.
- Cap on the project's annual O&M and A&G costs for a specified period of time.
- Cap on the project return on equity for the life of the project.
- Cap on the equity percentage for a specified period of time.
- Cap on the project's annual revenue requirement for a specified period of time.
- Financial penalty for failure to meet schedule.

(ISO Application Workbook)

HWT indicated that for its proposal 6 it is constructing the project in the configuration of alternative 1 in the ISO Functional Specifications.

HWT provided information showing its proposed substation interconnecting to PG&E's Round Mountain Substation through four 500 kV underground cable circuits. HWT indicated that the anticipated length of the 500 kV loop-in lines to be constructed by PG&E would be approximately 1500 feet per segment. (S-1)

Cost Containment Performance for Past Projects

HWT provided the same information regarding cost containment performance for past projects for its proposal 6 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 6.

Project Management Capabilities

HWT provided the same information regarding its project management capabilities for its proposal 6 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 6.

Project Risks and Mitigation of Risks

HWT provided the same information regarding project risks and mitigation of risks for its proposal 6 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 6.

3.12.5 Information Provided by HWT for Proposal 7

Cost Containment

HWT indicated that it is offering robust binding cost containment for the project, including a firm project cost cap and cap on return on equity with very narrow exclusions. Specifically, HWT indicated that it is offering the following cost containment measures, which are also reflected in its project financial model:

- Overall project cost cap, with specified exclusions.
- Cap on the project's annual O&M and A&G costs for a specified period of time.
- Cap on the project return on equity for the life of the project.
- Cap on the equity percentage for a specified period of time.
- Cap on the project's annual revenue requirement for a specified period of time.
- Financial penalty for failure to meet schedule.

(ISO Application Workbook)

HWT indicated that for its proposal 7 it is constructing the project in the configuration of alternative 2 in the ISO Functional Specifications.

Cost Containment Performance for Past Projects

HWT provided the same information regarding cost containment performance for past projects for its proposal 7 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 7.

Project Management Capabilities

HWT provided the same information regarding its project management capabilities for its proposal 7 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 7.

Project Risks and Mitigation of Risks

HWT provided the same information regarding project risks and mitigation of risks for its proposal 7 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 7.

3.12.6 Information Provided by HWT for Proposal 8

Cost Containment

HWT indicated that it is offering robust binding cost containment for the project, including a firm project cost cap and cap on return on equity with very narrow exclusions.

Specifically, HWT indicated that it is offering the following cost containment measures, which are also reflected in its project financial model:

- Overall project cost cap, with specified exclusions.
- Cap on the project's annual O&M and A&G costs for a specified period of time.
- Cap on the project return on equity for the life of the project.
- Cap on the equity percentage for a specified period of time.
- Cap on the project's annual revenue requirement for a specified period of time.
- Financial penalty for failure to meet schedule.

(ISO Application Workbook)

HWT indicated that for its proposal 8 it is constructing the project in the configuration of alternative 2 in the ISO Functional Specifications.

Cost Containment Performance for Past Projects

HWT provided the same information regarding cost containment performance for past projects for its proposal 8 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 8.

Project Management Capabilities

HWT provided the same information regarding its project management capabilities for its proposal 8 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 8.

Project Risks and Mitigation of Risks

HWT provided the same information regarding project risks and mitigation of risks for its proposal 8 as it did for its proposal 1. See the information set forth in Section 3.12.1 regarding this aspect of HWT's cost containment proposal for its proposal 8.

3.12.7 Information Provided by LSPGC

Cost Containment

LSPGC proposed several cost containment mechanisms, as listed below:

- Binding capital cost cap of $75.5 million, with the exceptions described below.
- AFUDC included in project cost cap.
- Binding return on equity cap of 9.80% for the life of the project.
- Binding equity percentage cap of no more than 45% equity for the life of the project.
- Binding annual revenue requirement cap for the first 15 full calendar years of project operations that would not exceed a total of $120.7 million for those 15 years. The binding annual revenue requirement cap would be applied annually and would include O&M costs, A&G costs, book depreciation, cost of debt, return on equity, and taxes for the project. To the extent project revenue requirements were lower than the binding annual revenue requirement cap in any given year, such difference would be added to the binding annual revenue requirement cap the following year to result in a revised binding annual revenue requirement cap.

If in any year the project revenue requirements were greater than the binding annual revenue requirement cap, LSPGC would not be able to recover these revenues in its rates, except to the extent the excess amount was attributable to excluded costs. The annual revenue requirement cap at its highest would be $9.6 million and at its lowest would be $6.7 million.

- On-time schedule financial incentive that would reduce LSPGC's return on equity by 2.5 basis points for every month that the project is delayed up to a total of 30 basis points.

(ISO Application Workbook)

LSPGC indicated that changes to LSPGC's binding cost cap would only be allowed for costs that result from (1) a change in ISO project requirements or the ISO Functional Specifications or requirements caused by an interconnection agreement or interconnecting PTO, (2) a change in law that becomes effective after the submission, or (3) force majeure type events, including but not limited to Uncontrollable Force (as defined in the ISO Tariff), uninsured losses (for example, damage due to an earthquake that requires additional project investment greater than the insurance coverage), or impacts from environmental contamination or damage not caused by LSPGC or its contractors. LSPGC clarified that the following actions would not be a basis for LSPGC to seek relief from its cost cap and other cost containment measures: (1) any siting authority directive to relocate the project to a site different from the primary or alternative sites identified by LSPGC; (2) a siting authority decision to require an increase in the amount of environmental mitigation beyond that assumed in LSPGC's proposal; (3) a siting authority decision requiring LSPGC to change the proposed structures, equipment, or transmission lines associated with the project (unless the changes are so fundamental as to be inconsistent with the APSA's description of the project); and (4) any delay in the receipt of LSPGC's siting authorizations. LSPGC also clarified that failure by one of LSPGC's preferred vendors to meet LSPGC's requirements would not be a basis for LSPGC to claim relief from its proposed cost cap or other cost containment measures. (ISO Application Workbook)

LSPGC indicated that this combination of cost commitments provides the ISO with cost certainty on more than 90% of the net present value of the revenue requirements for the project. (M-1)

LSPGC indicated that it is constructing the project in the configuration of alternative 1 in the ISO Functional Specifications.

LSPGC indicated that its proposal would minimize anticipated PG&E interconnection costs because the existing Round Mountain to Table Mountain 500 kV transmission lines are located on the site. LSPGC indicated that it would construct its interconnecting switchyard directly adjacent to the existing 500 kV lines. LSPGC indicated that because of the proximity of its proposed take off structures to the existing 500 kV lines (less than 500 feet), LSPGC expects PG&E will need to construct only two double circuit or four single circuit dead end structures outside of the switchyard. (S-1)

Cost Containment Performance for Past Projects

LSPGC provided examples of its cost performance regarding project budget for seven transmission line projects and ten substation projects. LSPGC indicated that all projects, except for two, were at or below budget. LSPGC indicated that one transmission line project and one substation project were above budget by about 4% and 14%, respectively, both due to changes in scope. (P-3)

Project Management Capabilities

LSPGC indicated that its project director would be the primary point of contact for the ISO and would be responsible for guiding LSPGC's day-to-day activities and overseeing all deliverables. LSPGC indicated that the project director would be supported by a highly qualified team of managers and subject matter experts with responsibilities for project execution within key project areas:

- Real estate
- Engineering & procurement
- Regulatory, environmental & compliance
- Construction

LSPGC indicated that it has already begun the process of planning and anticipating the project timelines, deliverables, and budgets, including the following steps:

- Executed exclusive option to purchase contracts for the preferred site and the alternative site;
- Advanced stage of negotiation of an EPC agreement with its proposed STATCOM design and construction firm for equipment supply and construction;
- Executed a master services agreement with its proposed primary engineering firm;
- Completed 30% engineering design;
- Prepared specifications for and competitively bid the following project components: electrical, civil, testing and commissioning, and STATCOM building;
- Performed environmental field surveys (wetlands, cultural, and threatened and endangered species) on the preferred site and alternative site;
- Performed geotechnical borings; and
- Developed a detailed project budget and schedule based on the preferred site and project requirements, informed by competitive bids for key materials and services.

LSPGC indicated that the project budget at financial close would be approved by executive management and would be the basis of the financing with the project lenders. LSPGC indicated that, subsequent to budget approval, the project director would track all costs and report budget variances to executive management and that any non-budgeted items would require additional approval by executive management. LSPGC indicated that throughout each phase of the project actual costs would be used to determine which are tracking as budgeted and which need additional attention to bring them back in line. LSPGC indicated that, during each phase of the project, managers and their consultants or contractors would need to receive approval from the project director before incurring any cost paid by LSPGC. LSPGC stated that it has routinely used this process to successfully energize its projects at or under budget.

LSPGC indicated that management of the master project schedule would include strict monitoring processes that would track progress toward key milestones and analyze schedule impacts compared to the baseline schedule. LSPGC indicated that mitigation processes and immediate remedies would be included in the project delivery program to address any real or perceived issues in schedule slippage. (P-4)

LSPGC listed the key roles in its organization and provided an organization chart for development, construction, and operations. LSPGC indicated that the project director would manage the day-to-day activities of the project team, be the primary point of contact for the ISO, have overall responsibility for the project through energization, and be provided the necessary authority and resources by executive management to successfully complete the project. (P-5)

Project Risks and Mitigation of Risks

LSPGC provided the following examples showing how it has confronted and resolved major issues during a project:

- innovative tubular guyed-V structure design which provided specific environmental mitigation benefits to protect sensitive species (greater sage grouse and Mojave desert tortoise) and also provided for a lower project cost;

- computational fluid dynamic modeling, fine mesh finite element analysis, wind tunnel testing, and full-scale field testing both on-site and off-site for mitigation of wind-induced vibration; and

- alternative foundation construction plans developed to handle subsurface conditions in various areas.

LSPGC also provided an example of one of its projects (developed by Cross Texas Transmission) where its affiliate was able to deliver its transmission line facilities at a cost 4% less than the initial planning estimates while the costs for other transmission service providers in competitive renewable energy zones were 24% to 69% higher than these estimates. (P-3)

LSPGC identified numerous risks and proposed mitigation measures, including in the following areas:

- APSA
- Interconnection agreements
- Project opposition
- CPUC final order delay
- Land acquisition
- Ability to obtain approval from the CPUC as required
- Environmental survey
- Project impact to wetlands
- Geotechnical survey
- Private rights-of-way acquisition
- Real estate acquisition costs
- Foundation design changes
- Station engineering
- Engineering
- U.S. Army Corps of Engineers permit

LSPGC stated that if selected, it would have the resources to complete both this project and the Gates dynamic voltage support project within budget, without negatively impacting either project. (P-7)

3.12.8 Information Provided by SEGG for Proposal 1

Cost Containment

SEGG indicated it has taken all available and prudent steps to contain the total cost for the project, as discussed below:

- Has formed exclusive partnerships with technology providers, an EPC company, an engineering firm, and an O&M services provider to ensure a firm price based on the assumptions used to develop its proposal.
- Has proposed a construction cost cap with specified exclusions and agreed to bear a specified portion of costs above the cap if exclusions are triggered.
- Has proposed a cap on the project return on equity for the life of the project.
- Has worked with landowners to execute an option to purchase two parcels of land.
- Has had detailed dialogue with Tehama County and other key stakeholders in the area to ensure that the project sponsor has a clear understanding of the process to exit the land from Williamson Act encumbrance and has a reasonable estimate for the costs to accomplish this.
- Has assembled a team of highly skilled, established, and experienced professionals (development, environmental, and legal) for the project to ensure that every project-related issue is identified early and addressed in a most efficient and cost-effective manner.

(P-7, ISO Application Workbook)

SEGG indicated that for its proposal 1 it is constructing the project in the configuration of alternative 1 in the ISO Functional Specifications.

SEGG estimated the length of PG&E's interconnection transmission lines as follows: Round Mountain #1 -2900 feet; Round Mountain #2 -- 4400 feet; Table Mountain #1 - 6650 feet (shown slightly longer to provide room for future corridor use); and Table Mountain #2 – 6700 feet (shown slightly longer to provide room for future corridor use). (T-8)

Cost Containment Performance for Past Projects

SEGG provided examples of its performance regarding project budget for four transmission line projects. SEGG indicated that two of the four projects were completed under budget, one project is currently under development, and cost information for the fourth project is not available. (P-3)

SEGG also provided historical budget performance data for its proposed construction contractor, O&M services provider, and equipment manufacturer. Of the fifteen projects for which SEGG provided budget performance information, all were over budget. (P-3)

Project Management Capabilities

SEGG indicated that it is ready to allocate resources immediately to start environmental permitting and finalize contracts with all team members and that most of the engineering activities would begin coincidental with the execution date of the APSA. SEGG indicated that once all authorizations are completed and land acquired, SEGG would proceed to financial closing for the long-term debt and issue a notice to proceed to all contractors. SEGG indicated that from this point, engineering would drive the procurement of needed materials and equipment.

SEGG indicated that the critical and long lead-time materials and equipment required for the project would be scheduled to arrive by the anticipated construction deadlines for each of these items. SEGG indicated that construction of STATCOM and high-voltage interconnect yards would be assessed and accomplished first. (QS-3)

SEGG indicated that the project sponsor, through different contractors, would develop the following plans prior to execution, and that each would include a team led by experienced personnel who would report the weekly progress to the assigned head of the project:

Stage 1

- Project management system
- Land acquisition plan
- Permitting plan
- Public outreach plan
- Construction management and contract plan

Stage 2

- Quality assurance/quality control system
- Procurement plan
- Logistics plan (developed to ensure that the objectives for delivering material and people to and from the site are met)
- Health and safety plan
- Project execution, including work breakdown structure
- Engineering records system
- Environmental management plan
- Labor relations plan
- Electrical studies
- Interconnection studies (application to PG&E)

(P-4)

SEGG indicated that its chief executive officer would be overseeing the successful completion of the project. SEGG indicated that its proposed project manager brings more than 38 years of experience in the electric power industry. SEGG indicated that its proposed asset manager is a senior vice president at Starwood Energy and that the SEGG lead for this proposal has extensive experience working with the ISO.

SEGG indicated that all contractors would be directly engaged through service or supply contracts for their relevant scopes. SEGG indicated that during the preparation of its proposal, SEGG developed a full division of responsibilities matrix with its proposed contractors covering most relevant aspects of the project, including but not limited to permitting, land acquisition, design, procurement, construction, commissioning, operation, and maintenance of the assets. (P-5)

Project Risks and Mitigation of Risks

SEGG provided some examples that show how it confronted and resolved major issues during a project:

- extensive experience of the development team, good communication, industry and government relationships, and strong partnerships with engineering and construction partners to successfully resolve National Environmental Policy Act challenges;

- physical challenges and unforeseen obstacles when laying cable in the Hudson River and when making landfall into Manhattan; and

- managing currency and supply chain risk for a European-based cable manufacturer and construction contractor, dealing with interconnection protocols in two independent system operator regions (PJM and NYISO), and managing challenging conditions for the installation of one of the longest subsea cables in North America.

SEGG also provided attachments with historical performance data for its proposed contractors. (P-3)

SEGG identified other risks and mitigation measures in the following areas: (P-7)

- Lack of detailed system data, including key system parameters required for design,
- Sub-synchronous resonance studies,
- Environmental permitting and mitigation,
- Williamson Act, and
- Cost containment strategy.

SEGG indicated that if both this project and the Round Mountain dynamic voltage support project were to be awarded to SEGG, SEGG and its partners in the project would have the capability to complete both of the projects in accordance with the ISO's specifications and schedule. (P-7)

3.12.9 Information Provided by SEGG for Proposal 2

Cost Containment

SEGG indicated it has taken all available and prudent steps to contain the total cost for the project, as discussed below:

- Has formed exclusive partnerships with technology providers, an EPC company, an engineering firm, and an O&M services provider to ensure a firm price based on the assumptions used to develop its proposal.
- Has proposed a construction cost cap with specified exclusions and agreed to bear a specified portion of costs above the cap if exclusions are triggered.
- Has proposed a cap on the project return on equity for the life of the project.

- Has worked with the two landowners to execute an option to purchase two parcels of land.
- Has had detailed dialogue with Tehama County and other key stakeholders in the area to ensure that the project sponsor has a clear understanding of the process to exit the land from Williamson Act encumbrance and has a reasonable estimate for the costs to accomplish this.
- Has assembled a team of highly skilled, established, and experienced professionals (development, environmental, and legal) for the project to ensure that every project-related issue is identified early and addressed in a most efficient and cost-effective manner.

(P-7, ISO Application Workbook)

SEGG indicated that for its proposal 2 it is constructing the project in the configuration of alternative 1 in the ISO Functional Specifications.

SEGG estimated the length of PG&E's interconnection transmission lines as follows: Round Mountain #1 - 2900 feet; Round Mountain #2 -- 4400 feet; Table Mountain #1 - 6650 feet (shown slightly longer to provide room for future corridor use); and Table Mountain #2 – 6700 feet (shown slightly longer to provide room for future corridor use). (T-8)

Cost Containment Performance for Past Projects

SEGG provided the same information regarding cost containment performance for past projects for its proposal 2 as it did for its proposal 1. See the information set forth in Section 3.12.8 regarding this aspect of SEGG's cost containment proposal for its proposal 2.

Project Management Capabilities

SEGG provided the same information regarding its project management capabilities for its proposal 2 as it did for its proposal 1, except that for proposal 2 SEGG indicated that construction of SVC (rather than STATCOM) and high-voltage interconnect yards would be assessed and accomplished first. (QS-3). See the information set forth in Section 3.12.8 regarding this aspect of SEGG's cost containment proposal for its proposal 2.

Project Risks and Mitigation of Risks

SEGG provided the same information regarding project risks and mitigation of risks for its proposal 2 as it did for its proposal 1. See the information set forth in Section 3.12.8 regarding this aspect of SEGG's cost containment proposal for its proposal 2.

3.12.10 Information Provided by SPT1

Cost Containment

SPT1 proposed:

- A binding capital cost cap, subject to specified exclusions.
- An O&M cap for a specified period of time, subject to certain exclusions.

(ISO Application Workbook)

SPT1 indicated that it is constructing the project in the configuration of alternative 1 in the ISO Functional Specifications.

SPT1 indicated that its site is adjacent to PG&E's 500 kV Round Mountain-Table Mountain transmission lines and abuts PG&E's right-of-way. SPT1 indicated that PG&E's loop-in lines should be able to fly directly into the proposed switchyard without any additional structure beside the dead-end structures that will be required to turn the lines, thus reducing PG&E's costs. (S-1)

Cost Containment Performance for Past Projects

SPT1 provided budget performance information for transmission and substation projects as follows:

- SPT1 provided budget performance information for six transmission projects, the largest being $7 million; SPT1 indicated that all six were completed within budget.
- SPT1 provided budget performance information for six substation projects developed by Southern Company or its affiliates, the largest being $22 million; SPT1 indicated that all six were completed within budget.
- SPT1 provided budget performance information for eleven substation or reactive support projects that SPT1's equipment supplier was involved in, the largest being $30 million; SPT1 indicated that all eleven projects were completed at or under the EPC contracted price except where the client agreed to scope changes.

SPT1 indicated that its equipment manufacturer has provided turnkey EPC services for more than 30 STATCOM and SVC installations in North America but that the supplier was unable to share detailed information on many of these projects as they were all performed under contracts with third parties that are confidential. (P-3)

Project Management Capabilities

SPT1 indicated that the project would be managed by a team consisting of SPC's transmission, legal, state and local affairs, project finance, commercial optimization, environmental permitting and compliance, EPC project management, project development, operations and maintenance, and business origination departments. (QS-1)

SPT1 indicated that project management and scheduling would be coordinated and managed by the foregoing team. SPT1 indicated that project scheduling would be managed using Industry standard project management software (Primavera, MS Project) with an itemized list of all major planned construction activities. SPT1 indicated that activities would be linked to develop a critical path with appropriate predecessors and successors, as well as incorporate environmental restrictions, clearance requirements, including proper notifications for outages, and the commissioning timeline. SPT1 indicated that the project schedule would be tracked consistently with weekly and monthly status reports being produced to ensure the project remained on schedule. (P-4)

SPT1 provided organization charts and resumes of the management and organizations that would be committed to the scope of this project. SPT1 indicated that the proposed management structure for the project would be the following:

- Project Director - overall responsibility of supporting the team members and the successful encompassing of the project into the company's operating assets. SPT1 indicated that the project director reports to the chief development officer and senior vice president for SPC, who would have approval authority for all construction activities related to the project.
- Project Manager - would report to the project director. SPT1 indicated that the project manager would have responsibility for the scope and schedule for the project, which would include the selection and direction of subcontractors that successfully undergo the procurement process of safety, quality, and technical experience.
- Construction Manager - would report to the project manager. SPT1 indicated that the construction manager would be responsible for ensuring all scopes of work performed with the project are performed in accordance with technical requirements, safety and environmental conditions, engineered drawings, applicable code requirements, and industry standards. SPT1 indicated that on-site superintendents or lead representatives from each subcontractor selected for the project would report to the construction manager.

SPT1 indicated that the individuals selected to fulfill each of the roles within the project management structure are currently being evaluated based on the forecasted project timeline and the experience and capabilities of available personnel. SPT1 indicated that it would ensure that the assigned project manager and construction manager would have the relevant experience and capability to complete the proposed project. SPT1 indicated that its transmission team would work closely with SPC's development team, providing support as needed on all aspects of this project.

SPT1 indicated that its primary equipment manufacturer and EPC contractor's project management would report to SPT1's project manager, the on-site construction manager would report to SPT1's construction manager, and subcontractors would report up through the equipment manufacturer and EPC contractor's project manager. (P-5)

Project Risks and Mitigation of Risks

SPT1 described a number of project risks, two of which are set forth below, along with a discussion of proposed mitigation:

1. SPT1 indicated that the CPUC would likely be the lead agency for the state and would issue the CPCN, which would be required prior to start of construction. SPT1 noted that the CPUC approval process for the Suncrest Dynamic Reactive Power Support Project recently took over 3.5 years to complete. SPT1 indicated that because the ISO's schedule anticipates selection of the approved project sponsor in in the first quarter of 2020 and requires the project to be in-service by June 2024, a lengthy CPUC approval process would put pressure on the ability of any project sponsor to meet the required in-service date. SPT1 indicated that Southern Company and SPT1 have extensive experience navigating regulatory and permitting processes and would lead SPT1's efforts in navigating this process. SPT1 indicated that it has already contracted its environmental consultants and law firms to assist on this project and that they, among

others, would bring additional experience, knowledge, and expertise to the process. In order to expedite the process as much as possible, SPT1 indicated that it would reach out to the CPUC as early as possible following selection, would proceed with the required environmental studies and reviews on an expedited basis, and would work with the ISO to ask the CPUC to consider the reliability need date for the project. SPT1 indicated that its team has reviewed the experiences of the Suncrest project's approval process and would apply lessons learned to avoid potential delays where possible.

2. SPT 1 indicated that the United States federal government has recently levied import tariffs on various goods and services from around the world and that tariffs could be put in place that would impact cost of some components of the project. SPT1 indicated that it would work diligently with its EPC contractor and equipment manufacturers to minimize any impacts to the ISO and its customers and would work with the ISO in good faith on any ideas that the ISO may have to mitigate this cost risk. (P-7)

3.12.11 Information Provided by Tenaska

Cost Containment

Tenaska proposed the following binding cost containment measures:

- Return on Equity Cap: Tenaska proposed a binding commitment for a return on equity, inclusive of all incentives. Tenaska indicated that, as a pass-through entity, it would not seek an income tax allowance in its revenue requirement. Tenaska indicated that this lower revenue requirement would be beneficial to California ratepayers.
- Development and Construction Cost Cap: Tenaska proposed a capital cost cap subject to specified exclusions and cap adjustment provisions.
- O&M Cost Cap: Tenaska proposed an O&M cost cap for a specified period.
- Equity Cap: Tenaska proposed to cap equity in the capital structure at a specified percent for life of the project.

(P-7, ISO Application Workbook)

Tenaska indicated that it is constructing the project in the configuration of alternative 1 in the ISO Functional Specifications.

Tenaska indicated that the anticipated lengths of the four 500 kV loop-in lines to be constructed by PG&E are: Round Mountain Line 1 -- 2,330 feet; Round Mountain Line 2 -- 560 feet; Table Mountain Line 1 -- 190 feet; and Table Mountain Line 2 -- 450 feet.

Cost Containment Performance for Past Projects

Tenaska provided budget performance information regarding five transmission line and seven substation projects where it had direct involvement in the project. The transmission line project costs were in the range of $4.4 to $50 million. The substation project costs were in the range of $5 to $12 million.

Tenaska indicated that all of the transmission line and substation or switching station projects listed were completed within budget. (P-3)

Project Management Capabilities

Tenaska indicated that it has assembled a highly qualified, experienced, and sufficiently sized team with the knowledge and skill to design, construct, operate, and maintain the project. It indicated that its team would include internal resources, consultants, and contracted parties, each with extensive experience in the successful greenfield development, construction, financing, and operation of large-scale power generation and transmission equipment, including projects substantially similar to this project. Tenaska indicated that the core team alone has more than 95 years of combined experience in the energy industry.

Tenaska proposed the following scope and approach for project management and scheduling for the project:

- Oversight and management of the site preparation contract (clearing, grading, storm water drainage, access roads, laydown etc.)
- Oversight and management of station service and back feed power contracts, T-1 communication lines with the ISO, PG&E and the STATCOM manufacturer
- Periodic project meetings with the ISO and PG&E for design review, interconnection, outage planning, testing, and commissioning
- Coordination with the Tehama County planning department
- Review and approval of key design documents, vendor shop inspections and witnessing factory acceptance tests, supporting weekly calls and monthly contractor site meetings, approval or rejection of change orders, and monitoring of non-conformance and quality issues.
- Enforcement of EPC, manufacturer, and various project contract obligations and minimization of change orders.
- Enforcement of all project permits, including environmental compliance
- Monitor and maintain project safety, quality (both shop and site), budget, schedule, and community relations
- Construction management, including site supervision and monitoring contractor quantities, productivity, and craft levels
- Support start-up and commissioning, including system walk downs, identification of quality and punch list items, and witness and approve critical milestones, such as outage planning and back feed energization
- Witness and approve plant performance and demonstration tests
- Management and processing of lender draw requests and project invoices
- Reporting to internal management, partners, lenders, and the lenders' engineer
- Reporting to Tehama County, the ISO, PG&E, and various agencies
- The core engineering and construction project team includes (1) a home office team comprised of a vice president of engineering and directors for technical services and transmission and (2) a site team comprised of a construction manager and field engineers

(P-4)

Tenaska provided an organization chart with a description of the experience of project team members, including the following:

> Tenaska indicated that the project manager possesses 30 years of experience with project engineering, construction management, project management, start-

up and commissioning, and cost control of power generation facilities, including experience with high voltage substations and transmission lines.

Tenaska indicated that the engineering manager possesses more than 30 years of experience with engineering review, start-up and commissioning, operation, maintenance, trouble shooting, and outage planning of various electric equipment, including utility scale electric generators, power transformers, switchgear, protection and relays, breakers, disconnect switches, high voltage substation, and transmission lines. (P-5)

Project Risks and Mitigation of Risks

Tenaska identified more than 15 risks that the project could potentially face and proposed mitigation measures related to schedule and cost, including the following:

Risk: Potential for capital cost overruns to increase the cost to ratepayers for the project

Proposed Mitigation: Tenaska indicated that its proposal includes a maximum capital cost above which Tenaska agrees not to include any excess costs into the project rate base.

Risk: Potential for public opposition to the project.

Proposed Mitigation: Tenaska indicated that it has already met with management of the County of Tehama and has a good understanding of community interests and objectives that are incorporated into the project design.

Risk: Potential for concerns associated with any historic view shed, nearby traditional cultural properties, or other cultural resources

Proposed Mitigation: Tenaska's indicated that it has strategically located its project site to avoid potential impacts to sensitive cultural resources. Tenaska indicated that its environmental consulting firm conducted preliminary cultural screening of the site and found no indications of any known cultural resources at the project site or interconnection areas.

Risk: Structure heights or locations in proximity to nearby public use airports may trigger Federal Aviation Administration review.

Proposed Mitigation: Tenaska indicated that its project site was strategically located to avoid potential impacts to aviation and that there are no known aviation related limitations at this site.

Risk: Fire risk

Proposed Mitigation: Tenaska indicated that it applied particular attention to fire prevention in the development and design of the project. Tenaska indicated that project location, security walls and fencing, substantial fire break setbacks in the project footprint, and equipment selection and quality considerations were all incorporated into the project, which substantially reduce the risk of fire. Additionally, Tenaska indicated that the project is located in very close proximity to the Paynes Creek fire station for quick response in the unlikely event of a fire in the area. (P-7)

3.12.12 Information Provided by TransCanyon

Cost Containment

TransCanyon indicated that it is proposing several cost cap mechanisms listed below:

- A binding capital cost cap with specified exclusions.
- A binding return on equity cap for the life of the project.
- A binding equity percentage cap for the life of the project.
- A binding cap on the project's annual O&M and A&G costs for a specified period of time. (Transmittal Letter, ISO Application Workbook)

TransCanyon indicated that it is constructing the project in the configuration of alternative 1 in the ISO Functional Specifications.

TransCanyon indicated that it expects that the loop in tie lines to be installed by PG&E would consist of four 500 kV circuits and would be supported by full tension structures accommodating conductor and static wire. TransCanyon indicated that it expects each PG&E loop-in line to be between approximately 1,560 to 2,350 feet to the project facility. (S-5)

Cost Containment Performance for Past Projects

TransCanyon provided information on its performance regarding project budget for six transmission line projects (above 200 kV) and four substation projects where its parent companies, PNW and BHE, have experience. TransCanyon indicated that it would rely on the experience of its team members and parent companies for this project.

TransCanyon indicated that four of the six transmission line projects listed have been completed at or below budget and that the remaining two transmission line projects are expected to be completed within budget.

TransCanyon indicated that two of the four substation projects listed were completed within budget, that one project exceeded the budget due to unrealized load forecasts and distribution upgrades and presence of archaeological resources, and that one more project is expected to be completed within budget. (P-3)

Project Management Capabilities

TransCanyon indicated that its team is composed of staffs of its affiliates and partners and provided an organization chart with each individual's role and experience. (QS-1)

TransCanyon indicated that its approach to project management during construction would be governed by the project execution plan. TransCanyon indicated that, upon selection by the ISO as the approved project sponsor, it would develop a project execution plan with its EPC contractor. TransCanyon indicated that, using best-practice methods, the project execution plan would describe the processes, roles, and responsibilities for each phase of the project, including:

- Health, safety, and environmental management
- Permitting and siting
- Community outreach
- Project development
- Construction and commissioning
- Operations

Application Phase
During the application phase, TransCanyon indicated that it conducted desktop diligence as well as on-site field surveys to determine feasible substation locations and line connection routes, identify any significant technical or environmental and permitting concerns, and establish a viable plan upon which to develop the project.

Permitting Phase
To expedite the permitting phase, TransCanyon indicated that it has conducted biological and archaeological surveys and developed a draft PEA, along with supporting preliminary engineering prior to submitting its proposal. TransCanyon indicated that it has conducted initial meetings with Tehama County and the Public Advocates Office to inform and collect feedback regarding the project. TransCanyon indicated that, upon selection by the ISO as the approved project sponsor, TransCanyon would be prepared to submit a final PEA along with an overall plan, schedule, and agreements necessary to deliver the required permits.

Project Development Phase
TransCanyon indicated that the project development phase would begin concurrently with, and extend beyond, the permitting phase. TransCanyon indicated that within the scope of this phase, the project team would make key decisions regarding:

- Final interconnection route
- Material specifications
- Support services
- Preparation of construction procurement documents

Construction and Commissioning Phase
As the final stages of the initial project cycle are reached, TransCanyon indicated that its project management team would continue contractor oversight and coordination, overseeing milestone progress and schedule compliance, quality assurance, budget tracking, and permit requirements. TransCanyon indicated that this would be accomplished by independent inspection, weekly and monthly reporting, and project meetings.

Operations Phase
TransCanyon indicated that PacifiCorp system operations would coordinate testing and commissioning of the project, and that, after successful commissioning, the PacifiCorp operations team, along with TransCanyon's contractors, would be expected to perform O&M functions through the O&M services agreement.

TransCanyon indicated that it would use Primavera software for the project schedule and that Primavera supports the development of a fully integrated schedule by the project parties carrying out the work in accordance with the business rules and structure.

TransCanyon indicated that the schedule would follow industry best practices and include the following constraints:

- No durations or reporting cycles greater than 30 days
- No start-to-finish logic links
- Minimal number of start-to-start or finish-to-finish logic links
- Physical percentage completion used only for progress reports

TransCanyon indicated that it would adhere to strict schedule control, using a number of methods, including but not limited to:

- Discipline schedule reports (e.g., environmental, permitting, procurement and construction) produced monthly (at a minimum) for each of the team members
- Field verification of actual installed quantities vs quantities scheduled
- Weighted progress measurement (similar to an earned value analysis)
- Staffing level analysis
- Vendor and third-party shipping reports and delays
- Owner issues

(P-4)

TransCanyon indicated that overall project management would be provided by the project manager, who would report to TransCanyon's Vice President of Project Delivery and that there are three major project work streams for which the project manager would have oversight: (1) permitting and siting, (2) engineering and design, and (3) construction delivery. TransCanyon indicated that it would lead the permitting and siting work stream, its EPC contractor would lead the engineering design of the substation and interconnection transmission line and oversee the construction contractor, and its STATCOM manufacturer would provide engineering, design, and installation of the STATCOM for the project. (P-5)

Project Risks and Mitigation of Risks

TransCanyon provided a description of its cost containment approach as follows:

- First, TransCanyon indicated that it invests up front in eliminating controllable risks, for example, by acquiring necessary right-of-way, or conducting geotechnical studies to identify potential issues that can be addressed in engineering and included in its proposed price.
- Next, to the maximum extent practical, TransCanyon indicated that it secures firm, fixed-price contracts with each of its suppliers before it submits a proposal and that this approach benefits customers by reducing TransCanyon's risk and thereby potentially reducing its required return and also by reducing the potential for cost overruns that would exceed the cap to which TransCanyon indicated that it would commit.
- Finally, TransCanyon indicated that it commits to cost containment and cost concessions that benefit customers in the form of lower rates and reduced risk of cost overruns and that each of these concessions is supported by the previous layer. TransCanyon indicated that it is confident that it can deliver on its proposal and meet its financial objectives, without the need to seek relief from customers in the case of unforeseen events.

TransCanyon indicated that its approach to cost containment is tied to its exclusive rights to a project site that supports demonstrably lower development costs to customers and its relationships with world class engineering, construction, and equipment providers. As the project sponsor, TransCanyon indicated that it would also reduce the cost of the project to customers by foregoing recovery of the cost of financing during construction, capping its total return on equity for the life of the project below its allowed rate, and capping its equity layer below its allowed rate.

TransCanyon indicated that it has offered to cap its O&M costs for ten years and indicated that this commitment is backed by warranty and fixed price contract arrangements for maintenance, which provide customers with additional assurance that TransCanyon would have no incentive to delay or unnecessarily accelerate necessary maintenance in order to manage its costs relative to it cap obligations, having already managed those risks before agreeing to accept them. TransCanyon indicated that its contract with its equipment manufacturer includes a performance guarantee, providing customers with assurance that costs would be contained, but availability would not suffer. (M-1)

TransCanyon identified specific risks and mitigation measures related to cost in several areas, including:

Engineering and Design
TransCanyon indicated that it is comfortable selecting and agreeing to fixed price contract terms with its EPC contractors up front, which allowed the team to focus on designing an engineered solution during the proposal phase.

Preliminary Outreach and Permitting
TransCanyon indicated that it held meetings with subject matter experts, including biologists, archaeologists, land planners, and landscape architects to thoroughly assess known environmental opportunities and constraints. TransCanyon indicated that this process included the identification of known and potentially sensitive or protected species, known culturally sensitive areas, visually sensitive areas, and recreation areas, and included both biological and archaeological surveys. With this information, TransCanyon indicated that it had the information needed to initiate a draft PEA, which would position it to be prepared to submit the final document to the CPUC immediately after the APSA is executed.

Engineering Risks
TransCanyon indicated that it has commissioned a geotechnical study that identified subsurface issues that could be addressed in the preliminary design.

Manufacturing Risks
Given the size and scope of its equipment supplier's manufacturing operations, TransCanyon indicated that it viewed the risk of manufacturing issues as low. TransCanyon indicated that it realized that inflation and currency risks associated with the lag between the proposal date and the date at which materials would be ordered could be substantial. TransCanyon indicated that it determined that its equipment manufacturer was best positioned to cost-effectively address this risk in the long-term, while TransCanyon would hold a small contingency in the short term.

Permitting Risks
TransCanyon indicated that it has focused on conducting extensive diligence to identify a site for the switching station that minimizes environmental impacts and is best-suited to support timely receipt of applicable permits.

Right-Of-Way Risks
TransCanyon indicated that it has mitigated this risk by executing a 40-acre purchase option agreement for the project site that is adjacent to the Round Mountain-Table Mountain 500 kV transmission lines.

Construction Risks
TransCanyon indicated that it has determined that its EPC contractor was best positioned to evaluate, mitigate, and manage certain construction risks, primarily related to fire, subsurface conditions, and weather events. TransCanyon indicated that it would not carry a contingency for these risks as its EPC contractor would be responsible for cost increases related to these items. With respect to other types of construction risks, TransCanyon indicated that it determined that its site diligence had mitigated these risks to levels that were low enough to warrant accepting these risks and holding a small contingency. (P-7)

Authority to Impose Binding Cost Caps

(P-8)

3.12.13 Information Provided by HWT for Proposals 1, 2, 3, 6, 7, and 8

HWT indicated that it would seek siting approval from the CPUC. HWT also indicated that because its transmission rates would be regulated by FERC, the binding cost containment measures that HWT proposes for the project would primarily be enforced by FERC, through the APSA and HWT's FERC-approved transmission rates. (P-8)

3.12.14 Information Provided by LSPGC

LSPGC indicated that it would seek siting approval from the CPUC and acknowledged the authority of the CPUC to impose a cost cap or cost containment measures. LSPGC also indicated that FERC would have the authority to enforce the cost cap and cost containment measures set forth in its proposal. (P-8)

3.12.15 Information Provided by SEGG for Proposals 1 and 2

SEGG indicated that it would seek siting approval from the CPUC and acknowledged the authority of the CPUC to impose a cost cap or cost containment measures, but it indicated that it does not anticipate that the CPUC would do so. (P-8)

3.12.16 Information Provided by SPT1

SPT1 indicated that it would seek siting approval from the CPUC and that the CPUC has cost control measures in place. (P-8)

3.12.17 Information Provided by Tenaska

Tenaska indicated that it would seek siting approval from the CPUC and/or Tehama County and acknowledged that FERC has authority to set rates and enforce agreements relating to cost recovery. (P-8)

3.12.18 Information Provided by TransCanyon

TransCanyon indicated that it would seek siting approval from the CPUC and acknowledged the authority of the CPUC to impose a cost cap or cost containment measures on the project and provided examples of prior instances in which the CPUC has imposed cost caps on new transmission projects. (P-8)

3.12.19 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 has considered the expected effectiveness of the project sponsors' overall cost containment capabilities, including but not limited to experience of cost containment performance on previous projects, project management and scheduling organizations and capabilities, experience of key individuals, the project risks and mitigation that each project sponsor identified, factors impacting 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 reliability need that the project is intended to address will not exist prior to June 1, 2024. 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 reserves the option 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; the differences in cost estimates are reflected in the binding capital cost caps proposed by each project sponsor. 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 Capital/Construction Cost Caps, Cost Containment Measures, and Cost Cap Increase Conditions

All six project sponsors committed to some form of binding capital/construction cost recovery caps for their twelve proposals, subject to certain specified conditions for adjustment. However, the proposals differed greatly in terms of the number of cost items being capped, the level of the caps, and the conditions under which the caps might be adjusted.

Consistent with the practice the ISO implemented in connection with the competitive solicitation for the Harry Allen-Eldorado Transmission Line project and to respect confidentiality concerns, the ISO only specifies the specific, detailed cost containment measures and conditions of the approved project sponsor. The cost containment measures and conditions proposed by the other project sponsors have been described only in very general terms.

All six project sponsors committed to binding capital/construction cost recovery caps for their twelve proposals, subject to certain specified cost exclusions. LSPGC's proposed capital cost cap was the lowest -- $75.5 million. Comparing only the levels of the proposed capital cost caps and specified cost exclusions to the caps (*e.g.*, AFUDC),[10] LSPGC's capital cost cap was the lowest, followed in order of next lowest cost by the capital cost caps in HWT's proposal 8, HWT's proposal 6, HWT's proposal 1, HWT's proposal 7, HWT's proposal 2, SPT1's proposal, Tenaska's proposal, HWT's proposal 3, SEGG's proposal 2, SEGG's proposal 1, and then TransCanyon's proposal.

Five of six project sponsors proposed binding cost containment commitments regarding return on equity and related taxes for the life of the project. Tenaska had the strongest proposal in this regard, followed by the proposals of LSPGC and TransCanyon, followed by SEGG's proposals 1 and 2, and then HWT, for its proposals 1-3 and 6-8.

Four project sponsors proposed to cap the percentage of equity for the project. LSPGC's proposal and TransCanyon's proposal were stronger than HWT's proposals 1-3 and 6-8 and Tenaska's proposal.

LSPGC proposed a 15-year annual revenue requirement cap not to exceed a total of $120.7 million for the first 15 years of operations. It was of longer duration than the only other proposed cap on annual revenue requirements, which was proposed by HWT, for its proposals 1-3 and 6-8. For the period where the caps overlapped, LSPGC's cap level was lower than the revenue requirement cap levels for HWT's proposals 1-3 and 6-7, but higher than the cap level for HWT's proposal 8.

Regarding O&M costs, the six project sponsors provided a wide range of cost estimates for their expected annual average O&M expenses for the project for their twelve proposals. None of the project sponsors proposed a cap on O&M costs at a specific dollar amount for the life of the project. HWT, for its proposals 1-3 and 6-8, SPT1, Tenaska, and TransCanyon proposed O&M cost caps for limited different periods of time. TransCanyon's proposal had the longest-lasting O&M cost cap, and the O&M cost caps in HWT's proposals 1-3 and 6-8, SPT1's proposal, and Tenaska's proposal, had the same duration. The lowest O&M cost cap was for HWT's proposals 1-2 and 6-8, followed by HWT's proposal 3, SPT1's proposal, TransCanyon's proposal, and then Tenaska's proposal, in that order. As indicated above, LSPGC proposed a 15-year cap on total and annual revenue requirements for its project that included O&M costs, and HWT proposed a limited term annual revenue requirement cap that also included its O&M costs, plus a separate O&M cost cap for its proposals. No project sponsor demonstrated why it would have inherently lower (or higher) O&M costs than any other project sponsor. Because the ISO cannot predict with a reasonable degree of certainty what the actual O&M cost differences between the project sponsors' projects ultimately

[10] Below the ISO provides a separate comparison of the various conditons under which the project sponsors propose to adjust their cost caps for specified occurrences.

would be or what O&M costs FERC would ultimately approve (or disapprove) for each project sponsor, the ISO has concluded that uncapped O&M costs are too uncertain under the specific circumstances and information presented here to ascribe significant weight or a specific quantitative value to them. That being said, the ISO's expert consulting firm ran scenarios using (any) capped and uncapped O&M costs for purposes of comparing the overall net present value of each proposal's revenue requirements.

Individual project sponsors proposed various conditions under which they would be permitted to adjust their cost caps for certain occurrences. The exceptions included standard force majeure-type conditions, as well as other specified exclusions unique to the individual project sponsor. LSPGC proposed the most robust restrictions on cost cap changes, followed by SPT1's and TransCanyon's proposals, and then Tenaska's proposal, SEGG's proposals 1 and 2, and HWT's proposals 1-3 and 6-8, in that order. The ISO considers the proposals of Tenaska and SEGG, for its proposals 1 and 2, to be slightly better than HWT's proposals 1-3 and 6-8 in this regard because they would agree to bear a specified amount of the costs above the cap if adjustments to the cost cap are triggered. The ISO views HWT's proposals 1-3 and 6-7 as better than HWT's proposal 8 regarding this particular aspect of cost containment because if HWT is unable to reach agreement with PG&E and the CPUC does not require co-location, HWT would need to relocate the project from its primary site, which would affect its binding cost cap proposal.

Given the diversity of the various binding cost containment measures and cost assumptions contained in the proposals, the ISO and its expert consulting firm conducted a comprehensive cost analysis and ran numerous scenarios to calculate illustrative revenue requirements for each project sponsor's proposal and examined a host of sensitivities to compare cost caps and binding cost commitments effectively and assess the impacts of any potential cost escalation. Among other cases, the ISO ran sensitivities utilizing uncapped elements based on project sponsor cost estimates (*e.g.*, cost of debt, capital expenditures, and O&M costs) and made certain adjustments in order to determine whether there might be conditions under which the proposals of the project sponsors with the strongest cost containment measures might compare differently. LSPGC's proposal had the lowest net present value for its calculated transmission revenue requirements in the vast majority of the scenarios that were run. In the case of the very few exceptions, HWT's proposal 8 had a lower net present value. However, as discussed below, the estimated costs of PG&E's anticipated interconnection facilities, which are an integral component of the overall project cost, were not considered in the scenario analyses.

Based on the foregoing analysis (not inclusive of PG&E interconnection costs), the various rate studies performed by the ISO's expert consulting firm, the nature and scope of each project sponsor's binding cost containment commitments, and the ISO's assessment of risks to the project cost caps, the ISO has concluded regarding this aspect of cost containment that LSPGC's binding cost containment measures (including cost caps and change limitations) proposal is better and provides greater cost certainty than the 11 proposals of the other five project sponsors. Based on the specific risks and circumstances of this project, the ISO regards HWT's cost containment proposal for its proposal 6 as the next strongest, followed in order by HWT's proposal 1, HWT's proposal 7, HWT's proposal 8, HWT's proposal 2, SPT1's proposal, HWT's proposal 3, Tenaska's proposal, SEGG's proposal 2, SEGG's proposal 1, and then TransCanyon's proposal. The ISO considers HWT's proposal 8 less favorable than some of the other proposals relative to where its basic capital cost cap would have placed the proposal because of the risks associated with lack of site control over the primary site (as discussed above and in Section 3.6) and the risk the cost cap would have to be revised if HWT is unable to reach agreement with PG&E or the CPUC does not require co-location, resulting in HWT having to relocate the project from its proposed site.

As indicated in the ISO Functional Specifications, the overall scope of this project involves both the portion of the project that is subject to competitive solicitation and PG&E's portion of the project to interconnect the approved project sponsor's dynamic reactive support facilities. As indicated in the ISO Functional Specifications, for alternative 1, the costs associated with PG&E's scope of work depend on the distance from the new switching station to the existing 500 kV lines. The ISO Functional Specifications indicated that the cost estimate for double circuit 500 kV lines and single circuit 500 kV lines is $4 million and $2.5 million per mile, respectively. The ISO Functional Specifications indicated that if the tie lines are less than one mile, they could be on double circuit towers. However, if the tie lines are one mile or longer, the circuits must be on single circuit towers. For alternative 2, the ISO Functional Specifications indicated that the cost estimate for PG&E's scope of work is $91 million and $43 million for Round Mountain and Table Mountain Substations, respectively. Thus, where a project sponsor proposes to locate its facilities and whether the project sponsor selects alternative 1 or alternative 2 can significantly affect the overall costs of the project.

LSPGC's and SPT1's proposals, which both propose to construct the project in the configuration of alternative 1 in the ISO Functional Specifications, have optimal sites adjacent to the existing 500 kV transmission lines, which minimize the PG&E interconnection costs. HWT's proposals 1-3 also are well positioned and would cause PG&E to incur slightly higher costs than LSPGC's and SPT1's proposals. Given their specific location in relation to PG&Es existing facilities, HWT's proposals 1-3 are very slightly better than Tenaska's proposal in this regard. Regarding projected PG&E interconnection costs, these proposals are followed in order by TransCanyon's proposal and then SEGG's proposals 1 and 2. HWT's proposal 6 would likely require 500 kV undergrounding to connect to PG&E's system, and this would cause PG&E to incur significantly higher costs than in connection with any of the foregoing proposals. HWT's proposals 7 and 8 both involve constructing the project in the configuration of alternative 2 in the ISO Functional Specifications and thus would result in estimated PG&E interconnection-related costs of $134 million, making PG&E's portion of the project prohibitively more costly than the other proposals.

Based on all cost considerations, including binding cost containment commitments, the proposed exclusions from binding cost containment commitments, and PG&E's estimated interconnection costs, the ISO has concluded that the strongest proposal from a cost containment and cost certainty perspective is LSPGC's proposal, followed in order by HWT's proposal 1, HWT's proposal 2, SPT1's proposal, HWT's proposal 3, Tenaska's proposal, HWT's proposal 6, SEGG's proposal 2, SEGG's proposal 1, TransCanyon's proposal, HWT's proposal 7, and then HWT's proposal 8.

Cost Containment Performance for Past Projects

In terms of completing past projects within the project budget, HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SPT1, Tenaska, and TransCanyon demonstrated a reasonable degree of success in meeting budgets; the ISO considers the cost overruns reported by the project sponsors either to be insignificant, or the project sponsors provided reasonable explanations of the circumstances that resulted in the overruns. SEGG, for its proposals 1 and 2, demonstrated relatively little experience in meeting project budgets successfully, as it only provided budget performance information for two completed projects of its own, and the budget performance information that it provided for the fifteen examples of projects completed by its team members showed that all were over budget. Consequently, the ISO considers there to be no material difference among the recent experience of HWT, for its proposals 1, 2, 3, 6, 7, and 8, LSPGC, SPT1, Tenaska, and TransCanyon in meeting project budgets and considers their experience to be better than the experience described by SEGG, for its proposals 1 and 2.

In any event, given that all project sponsors proposed specific cost containment measures, those measures have the most direct bearing on cost containment for this project.

Project Management Capabilities

The ISO determined that all six project sponsors provided a reasonable approach to professional project management for their twelve proposals and as result determined them to be comparable with regard to project management capabilities. Given that all project sponsors proposed cost containment measures, those measures have the most direct bearing on cost containment for this project.

Project Risks and Mitigation of Risks

All six 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 twelve proposals. All six project sponsors confirmed their ability to work on two projects simultaneously, if awarded both. All six project sponsors have taken steps to reduce risk. However, HWT's proposal 8 results in more risk and less certainty regarding obtaining the land rights necessary to build the project on its primary site or obtaining agreement with PG&E to use its land. Based on the foregoing considerations, the ISO considers the proposals of HWT, for its proposals 1, 2, 3, 6, and 7, LSPGC, SEGG, for its proposals 1 and 2, SPT1, Tenaska, and TransCanyon to be comparable and better than HWT's proposal 8 with regard to risk.

Overall Assessment

For purposes of the comparative analysis for this component of the factor, the ISO's analysis has considered the expected effectiveness of the project sponsors' overall cost containment capabilities, including but not limited to experience of cost containment performance on previous projects, project management and scheduling organizations and capabilities, experience of key individuals, the project risks and mitigation that each project sponsor identified, factors impacting cost, and proposed cost containment plans.

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 binding cost containment measures proposed by the project sponsors to be the most significant inputs into the comparative analysis for this component of the factor.

The ISO has determined that all twelve proposals of the six project sponsors are comparable with regard to project management capabilities and that the ten proposals of the other five project sponsors are better than SEGG's two proposals regarding cost containment performance on previous projects. Regarding project risks and mitigation of those risks, the ISO considers HWT's proposal 8 to pose some additional risk because HWT does not have site control and is proposing to site the project on PG&E property. If PG&E does not agree to such usage or the CPUC does not authorize HWT to use this property, HWT would have to move to its backup site, which could have cost implications because this event is excluded from HWT's cost cap provisions.

Regarding binding cost containment commitments and expected PG&E interconnection costs, the ISO determined that LSPGC's proposal is better than the proposals of HWT, SEGG, SPT1, Tenaska, and TransCanyon regarding this component of the factor, particularly given that LSPGC has proposed the most robust capital/construction cost cap, with the more limited cost increase conditions, and a lower project cost escalation risk than the proposals of the other project sponsors and whose proposal is comparable to or better than the other eleven proposals of the other five project sponsors regarding past performance, project management, and risks to budget. Also, the ISO anticipates that LSPGC's proposal (along with SPT1's proposal) will cause the least amount of PG&E interconnection costs. The ISO also determined HWT's proposal 1 is the next strongest proposal, followed in order by HWT's proposal 2, SPT1's proposal, HWT's proposal 3, Tenaska's proposal, HWT's proposal 6, SEGG's proposal 2, SEGG's proposal 1, TransCanyon's proposal, HWT's proposal 7, and then HWT's proposal 8.

As a result, after applying all of the foregoing considerations, the ISO has determined that LSPGC's project proposal is better overall than the other eleven project sponsor's proposals with regard to this component, followed in order by HWT's proposal 1, HWT's proposal 2, SPT1's proposal, HWT's proposal 3, Tenaska's proposal, HWT's proposal 6, SEGG's proposal 2, SEGG's proposal 1, TransCanyon's proposal, HWT's proposal 7, and then HWT's proposal 8.

Comparative Analysis of the Authority to Impose Binding Cost Caps

Because all six project sponsors have proposed binding cost caps for their twelve 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 process.

Overall Comparative Analysis

The ISO considers the first component of this factor (cost containment and cost cap) more important than the second (siting authority imposing a cost cap). Given that all six project sponsors offered a binding cost cap for each of their twelve 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 LSPGC's proposal is better than the other eleven proposals, followed in order by HWT's proposal 1, HWT's proposal 2, SPT1's proposal, HWT's proposal 3, Tenaska's proposal, HWT's proposal 6, SEGG's proposal 2, SEGG's proposal 1, TransCanyon 's proposal, HWT's proposal 7, and then HWT's proposal 8 with regard to this factor overall.

3.13 Selection Factor 24.5.4(k): Additional Strengths or Advantages

(Section 1 – Introduction, Section 3 - General Project Information, QS-1, QS-4, QP-1, QP-2, S-1, S-6, S-7, S-8, T-1, T-5, T-8, C-7, O-9, M-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 HWT for Proposal 1

Project Design

HWT's proposal 1 would follow the configuration of alternative 1 in the ISO Functional Specifications. HWT proposed: (1) a switching station with a BAAH configured bus, including three bays and six new bays plus space for four future bays along with two main buses; (2) two independent +/- 266 MVAr dynamic reactive support systems connected to a switching station via two independent overhead strain bus circuits, one for each independent system, designed to eliminate to the extent practical any single point of failure common to both installations; and (3) interconnection of the new switching station with the existing PG&E Round Mountain to Table Mountain 500 kV transmission lines by looping these lines into the new switching station and terminating them on four new breaker and a half bays. (Executive Summary)

HWT indicated that in order to satisfy the ISO Functional Specifications' stated requirements, it considered all the possible candidate technologies identified in Appendix 1 of the ISO's 2018-2019 transmission plan. HWT stated that its extensive modeling and analysis, combined with competitive pricing solicitations, indicated that a STATCOM-based solution is clearly the most efficacious and cost-effective fix for the identified reliability concerns. In its proposal 1, HWT proposed two +/- 266 MVAr STATCOM blocks in the configuration of alternative 1 of the ISO Functional Specifications to address the identified reliability problems. HWT indicated that it performed a detailed evaluation of the physical and electrical characteristics, and cost analysis, for the various types of dynamic reactive support technologies. (QP-1)

The project availability information provided by HWT indicated that the project would be designed to have forced outage availability of greater than 99%. (QP-1.e, S-7)

Other Advantages

HWT indicated that it is already a utility in California and is able to draw upon the extensive and long-standing local presence of its affiliate companies. HWT indicated that NextEra has invested $7.5 billion in California as of July 31, 2019.

HWT indicated that NextEra's extensive presence in California includes numerous personnel dedicated to operating its facilities. HWT indicated that NextEra has more than 172 full-time staff located throughout California with the ability to respond quickly to the needs of the project.

HWT indicated that NextEra's presence in California distinguishes HWT from other project sponsors seeking a foothold in California without previously having made a long-term investment or having the same experience and resources to apply to project development.

HWT indicated that it would be able to draw upon a wide range of resources from within NextEra under NextEra's support services model. HWT indicated that this support services model would enable that organization to apply best practices philosophy, a highly skilled workforce, and economies of scale across its companies. HWT indicated that these resources would give HWT access to pools of specialized operation and support talent that would eliminate its need to duplicate these resources and would reduce HWT's overall cost of service. HWT indicated that overall this would enable HWT to operate effectively and efficiently, to the ultimate benefit of California ratepayers.

HWT indicated that as a public utility in California it has a detailed, robust, and CPUC-approved wildfire mitigation plan. HWT stated that its wildfire mitigation plan was developed around a strong focus on prevention and situational awareness to minimize wildfire risk. (M-1)

3.13.2 Information Provided by HWT for Proposal 2

Project Design

HWT's proposal 2 would follow the configuration of alternative 1 of the ISO Functional Specifications. HWT proposed two independent +/- 266 MVAr dynamic reactive support systems, each consisting of two +/- 133 MVAr STATCOMs connected to the switching station via two independent overhead strain bus circuits, one for each independent system, designed to eliminate to the extent practicable any single point of failure common to both installations. HWT indicated that the new switching station would interconnect with the existing PG&E Round Mountain to Table Mountain 500 kV transmission lines by looping these lines into the new switching station and terminating them on four new breaker-and-a-half bays. (Executive Summary)

The project availability information provided by HWT indicated that the project would be designed to have forced outage availability of greater than 99%. (QP-1.e, S-7)

Other Advantages

HWT provided the same information regarding other advantages for its proposal 2 that it provided for its proposal 1, as discussed above in Section 3.13.1.

3.13.3 Information Provided by HWT for Proposal 3

Project Design

HWT's proposal 3 would follow the configuration of alternative 1 of the ISO Functional Specifications. HWT proposed: (1) a switching station with a BAAH configured bus, including six new bays plus space for four future bays along with two main buses; (2)

two independent +/- 236 MVAr dynamic reactive support systems, along with two independent 30 MW/27.5 MVA battery energy storage systems connected to the switching station via two independent overhead strain bus circuits, one for each independent system plus battery energy storage system block, designed to eliminate to the extent practical any single point of failure common to both installations and provide ISO operational flexibility and alternative uses inherent in battery energy storage systems; and (3) the interconnection of the new switching station with the existing PG&E Round Mountain to Table Mountain 500 kV transmission lines by looping these lines into the new switching station and terminating them on four new breaker and a half bays. (Executive Summary)

The project availability information provided by HWT indicated that the project would be designed to have forced outage availability of greater than 99%. (QP-1.f, S-7)

HWT indicated that the system could provide the additional benefit of reliably and economically storing and discharging electric energy upon demand. HWT indicated that the project would provide the following functionality, in addition to providing on-demand automatic dynamic VAR support:

- energy capacity during off-peak times,
- increased flexibility
- ancillary benefits (*e.g.*, frequency response, operating reserves)
- economic benefit to the surrounding area while providing increased energy efficiency and grid reliability,
- stable support to the electric grid, and
- support for state and local government renewable energy goals.

(S-1, QP-1)

HWT indicated that the State of California has developed an interest in battery energy storage systems in conjunction with its interest in renewable energy for the primary reason of its potential to assist in overcoming the lack of time synchronization between renewable peak output and peak electricity demand on the grid. HWT indicated that energy storage systems enable the capture of low-marginal cost energy from renewable sources, which can then be returned to the grid during periods of high demand and pricing that frequently do not coincide in time with maximum available generation output. HWT indicated that more grid applications have become suitable for battery energy storage systems as battery costs have decreased while performance and life have continued to increase. (QP-1a, S-1)

HWT indicated that with the type of inverter proposed for the project, it would expect higher losses and lower reliability at the individual inverter level, which would place this technology at a disadvantage to the SVC and multi-modular converter STATCOM from the sole perspective of reactive support, leading HWT to decide not to present a proposal based solely on a battery storage system. (S-1)

Other Advantages

HWT provided the same information regarding other advantages for its proposal 3 that it provided for its proposal 1, as discussed above in Section 3.13.1.

3.13.4 Information Provided by HWT for Proposal 6

Project Design

HWT's proposal 6 would follow the configuration of alternative 1 in the ISO Functional Specifications. HWT's proposal 6 included a new 500 kV switching station immediately adjacent to PG&E's existing Round Mountain Substation. HWT proposed: (1) a switching station with a BAAH configured bus, including three bays and six new bays plus space for four future bays along with two main buses; (2) two independent +/- 266 MVAr dynamic reactive support systems connected to a switching station via two independent overhead strain bus circuits, one for each independent system, designed to eliminate to the extent practical any single point of failure common to both installations; and (3) interconnection of the new switching station with the existing PG&E Round Mountain to Table Mountain 500 kV transmission lines by looping these lines into the new switching station and terminating them on four new breaker and a half bays. (Executive Summary)

The project availability information provided by HWT indicated that the project would be designed to have forced outage availability of greater than 99%. (QP-1.e, S-7)

Other Advantages

HWT provided the same information regarding other advantages for its proposal 6 that it provided for its proposal 1, as discussed above in Section 3.13.1.

3.13.5 Information Provided by HWT for Proposal 7

Project Design

HWT's proposal 7 would follow the configuration of alternative 2 in the ISO Functional Specifications. HWT proposed two independent +/- 281 MVAr dynamic reactive support installations, with one block interconnected with the existing PG&E Round Mountain 230 kV substation and the other block interconnected with the existing PG&E Table Mountain 230 kV substation. HWT indicated that the interconnection would consist of 230 kV underground cables, one circuit at each location. (Executive Summary)

The project availability information provided by HWT indicated that the project would be designed to have forced outage availability of greater than 99%. (QP-1.e, S-7)

Other Advantages

HWT provided the same information regarding other advantages for its proposal 7 that it provided for its proposal 1, as discussed above in Section 3.13.1.

3.13.6 Information Provided by HWT for Proposal 8

Project Design

HWT's proposal 8 would follow the configuration of alternative 2 set forth in the ISO Functional Specifications. HWT proposed two independent +/-281 MVAr dynamic reactive support installations, with one block interconnected with the existing PG&E

Round Mountain 230 kV substation and the other block interconnected with the existing PG&E Table Mountain 230 kV substation on land currently owned by PG&E. HWT indicated that the total installed MVAr capability would be +/- 562 MVAr and that each block would be located on land currently owned by PG&E immediately adjacent to the point of interconnection at Round Mountain and Table Mountain Substations. (Executive Summary)

The project availability information provided by HWT indicated that the project would be designed to have forced outage availability of greater than 99%. (QP-1.e, S-7)

Other Advantages

HWT provided the same information regarding other advantages for its proposal 8 that it provided for its proposal 1, as discussed above in Section 3.13.1.

3.13.7 Information Provided by LSPGC

Project Design

LSPGC's proposal would follow the configuration of alternative 1 in the ISO Functional Specifications. LSPGC proposed (1) a STACOM that would be operated in two completely independent and redundant blocks of +/- 264.5 MVAr with no single point of failure between the two units, and (2) a six position breaker-and-a-half switching station that would loop into the 500 kV lines between Round Mountain and Table Mountain Substations. LSPGC indicated that the STATCOM most effectively meets the requirements detailed in the ISO Functional Specifications while also minimizing project costs. LSPGC indicated that a STATCOM has multiple technical advantages, including superior dynamic performance, faster response time, superior output capability under low voltage conditions, smaller footprint, and less harmonic generation when compared to an SVC.

The project availability information provided by LSPGC indicated that, with the inclusion in the project of a spare three-phase transformer, the project would be designed to have forced outage availability of greater than 99%. (QP-1, S-1, S-6, S-7, S-8, T-1)

Other Advantages

LSPGC indicated that its proposal includes a binding capital cost cap, a binding return on equity cap, a binding equity percentage cap, a binding annual revenue requirement cap, and a schedule guarantee. LSPGC indicated that this combination of cost commitments provides the ISO with cost certainty on more than 90% of the net present value of the revenue requirements for the project. (M-1)

3.13.8 Information Provided by SEGG for Proposal 1

Project Design

SEGG's proposal would follow the configuration of alternative 1 in the ISO Functional Specifications. SEGG proposed two equally sized +/- 250 MVAr STATCOM units to provide the required +/- 500 MVAr of dynamic reactive support. SEGG indicated that the blocks would be independent of each other and there would be no single point of failure between them. SEGG indicated that the STATCOM blocks would be independently connected to a breaker-and-a-half 500 kV bus arrangement at the project site and that the bus arrangement would have the capability of expansion to accommodate additional generation interconnection requests in the area if needed. (Section 3, QP-1, QP-2)

Data provided by SEGG for its proposal showed forced outage availability of greater than 99% for the STATCOM system. (QP-2, O-9)

SEGG's proposal indicated that STATCOM technology provides the following advantages for reactive power support in Round Mountain Substation: (QP-1)

- The voltage control performance of STATCOM fully meets the ISO's requirements.
- The dynamic reactive power support range of STATCOM covers the full required ± 500 MVAR range.
- The response speed of STATCOM control is very fast and meets the ISO's requirement for response time.
- The reliability of STATCOM technology is high and operation and maintainability easy.

Other Advantages

SEGG attached an environmental compliance plan and indicated that the implementation of this plan would assure the protection and preservation of water resources, natural and built environmental features, vegetation resources, wildlife resources, and cultural and archeological sites. SEGG indicated that the plan describes actions necessary to comply with all federal, state, and local environmental rules and regulations and to provide an environmentally compliant workplace. (M-1)

SEGG attached an environmental organizational chart and indicated that this organizational chart shows the customized management of its environmental program in a systematic, comprehensive, and strategic manner. SEGG indicated that this chart illustrates how its contractors would integrate environmental compliance into the planning and execution of the project. (M-1)

SEGG attached a project safety plan and indicated that this plan outlines how its contractors would manage the risks and mitigate the hazards associated with the project to protect site personnel, visitors, and the general public from exposure to the health and safety hazards associated with the site. (M-1)

SEGG attached a fire protection and suppression plan and indicated that the plan identifies measures to be taken by its contractors to ensure that fire prevention and suppression techniques incorporate state, federal, and local requirements and the Bureau of Land Management into its standard way of doing business to provide compliance with rules and regulations on a daily basis. (M-1)

3.13.9 Information Provided by SEGG for Proposal 2

Project Design

SEGG's proposal would follow the configuration of alternative 1 in the ISO Functional Specifications. SEGG proposed two equally sized +/- 250 MVAr SVC blocks to provide the required +/- 500 MVAr of dynamic reactive support. SEGG indicated that the blocks would be independent of each other and there would be no single point of failure between them. SEGG indicated that the SVC blocks would be independently connected to a breaker-and-a-half 500 kV bus arrangement at the project site and that the bus arrangement would have the capability of expansion to accommodate additional generation interconnection requests in the area if needed. (Section 3, QP-1, QP-2)

Data provided by SEGG for its proposal 2 showed forced outage availability of greater than 99% for the SVC system. (QP-2, O-9)

SEGG's proposal indicated that the SVC technology that SEGG has included in its proposal 2 has the following advantages for providing reactive power support in Round Mountain Substation: (QP-1)

- The voltage control performance of SVC fully meets the ISO's requirements.
- The dynamic reactive power support range of SVC covers the full required ± 500 MVAr range.
- The response speed of SVC control is very fast and meets the ISO's requirement for response time.
- The reliability of SVC technology is very high and operation and maintainability easy.

Other Advantages

SEGG provided the same information regarding other advantages for its proposal 2 that it provided for its proposal 1, as discussed above in Section 3.13.8.

3.13.10 Information Provided by SPT1

Project Design

SPT1's proposal would follow the configuration of alternative 1 in the ISO Functional Specifications. SPT1 indicated that the proposed design consists of two independent +/- 250 MVAr STATCOMs that are stepped up from 46 kV to 500 kV via two separate three-phase transformers (one spare is also included to ensure rapid restoration in the event of a failure of one of the transformers). SPT1 indicated that these two STATCOM blocks would connect to a 500 kV breaker-and-a-half switchyard that is also part of the project.

The project availability information provided by SPT1 indicated that the project would be designed to have forced outage availability of greater than 99%. (S-2, S-7, O-21)

Other Advantages

SPT1 indicated it is an experienced developer, owner, and operator and maintains capabilities to execute projects through long-term operations. SPT1 indicated that the project fits within its expertise and current project portfolio. (M-1)

3.13.11 Information Provided by Tenaska

Project Design

Tenaska indicated that it determined that alternative 1, as described in the ISO Functional Specifications, would be the best overall solution for the ISO's need for dynamic reactive support from a cost and execution standpoint. Tenaska proposed a +/- 500 MVAr STATCOM facility comprised of two +/-250 MVAr STATCOM blocks designed for an actual rating of +/- 277.5 MVAr at 525 kV with a matching 277.5 MVAr 46.25-525 kV step-up transformer, allowing the STATCOM to produce a continuous +250 MVAr at the lowest ISO-specified operating voltage of 473 kV and continuous -291 MVAr at the point of interconnection. Tenaska indicated that each 250 MVAr STATCOM block would be designed for 100 percent isolation from the other, not sharing any component or subsystem. (QP-1)

The project availability information provided by Tenaska indicated that, with a unique configuration and design with extensive equipment and control redundancy, the project would be designed to have forced outage availability of greater than 99%. (S-1)

Other Advantages

Tenaska indicated that the advantages it would bring in support of its selection as an approved project sponsor include its team's experience in successful greenfield development, construction, financing, and operation of large-scale power generation and transmission equipment, including projects substantially similar to this project. Tenaska also provided information on its binding cost containment proposal, which includes a binding commitment for a capped pre-tax return on equity, a development and construction cost cap, an O&M cost cap, and a capital structure commitment. Tenaska indicated that contractors for the project would be selected through competitive solicitation, and it anticipates that the EPC contract would be a turnkey, fixed-price contract.

3.13.12 Information Provided by TransCanyon

Project Design

TransCanyon indicated that it intends to construct the project in the configuration of alternative 1 in the ISO Functional Specifications because it dramatically reduces costs and risk associated with the related interconnection facilities relative to alternative 2. TransCanyon's proposal included a greenfield three-bay, six position 500 kV breaker-and-a-half switchyard with a new +/- 500 MVAr STATCOM and space for expansion to a total of five bays and 10 positons in the future. TransCanyon indicated that the STATCOM reactive support device would be installed in equally sized blocks separately and independently connected to the 500 kV BAAH switchyard to accommodate maintenance and provide for redundancy, with no common points of failure. TransCanyon indicated that the proposed ratings for the two STATCOM blocks would be +/- 265 MVAr defined at the 500 kV transformer bushing.

The project availability information provided by TransCanyon indicated that the project would be designed to have forced outage availability of greater than 99%. (M-1, S-1, S-6, S-7, S-8)

TransCanyon indicated that it considered several different reactive support device solutions for the project, including SVCs, STATCOMs, synchronous condensors, and hybrids and contracted with consultants to perform extensive studies to determine what reactive support device solution would best meet the project's requirements. TransCanyon indicated that the conclusion was that the proposed STATCOM solution would be the optimal device to meet applicable high and low voltage requirement criteria for normal and emergency conditions and provide other system benefits. TransCanyon indicated that the STATCOM acts quickly to maintain system voltage during the dynamic timeframe and allows a quicker transient voltage recovery to counteract the impacts of existing inverters that employ momentary cessation. TransCanyon identified several reasons why the STATCOM solution was determined to be the optimal reactive support device for the issues identified in the Round Mountain area. (S-7)

Other Advantages

TransCanyon indicated that selecting alternative 1 rather than alternative 2 set forth in the ISO Functional Specifications would dramatically reduce costs and risks to customers while also delivering greater reliability benefits. (M-1)

TransCanyon also indicated that its proposed solution minimizes construction expenses and environmental impacts. TransCanyon indicated that the Round Mountain-Table Mountain 500 kV transmission lines cross remote regions in northern California, which in many instances are characterized by limited road access, challenging grades, geotechnical conditions, and elevated fire risk that can lead to cost uncertainty. TransCanyon indicated that its proposed site minimizes cost, risk, and environmental impact and is materially superior to alternatives because it has excellent access to roads and will require less cut and fill than other potential alternatives. TransCanyon indicated that it identified no environmental issues, and its site is located approximately 3.5 miles from a joint county and Cal Fire facility. (M-1)

TransCanyon indicated that it is using world-class engineering, construction, and equipment providers and proposing cost containment measures that do not compromise quality. (M-1)

TransCanyon indicated that it and its affiliates have a uniquely strong history of cooperation with PG&E. TransCanyon indicated that its familiarity with PG&E's organization and relationships with PG&E personnel would facilitate effective collaboration, which TransCanyon views as a critical success factor for the project. (M-1)

TransCanyon indicated that it and PG&E have established a strategic alliance, pursuant to which the two companies have agreed to pursue development of competitive transmission projects in and connected to the ISO footprint. (M-1)

TransCanyon indicated that PacifiCorp, an affiliate, has commenced construction of PacifiCorp's Latham STATCOM project, to be delivered on a turnkey basis by TransCanyon's proposed STATCOM manufacturer, scheduled to go into service in October 2020, with a scope similar to this project. TransCanyon indicated that this would provide California customers with a unique opportunity to leverage all of the lessons learned accumulated by an integrated team that would have recently completed the design and construction of comparable facilities. TransCanyon indicated that this knowledge would be a significant risk mitigation opportunity that only TransCanyon could offer. TransCanyon indicated that PacifiCorp as the operator and asset manager for the Latham STATCOM would bring experience and lessons learned to this project. (M-1)

TransCanyon indicated that it invests up front in eliminating controllable risks, for example, by acquiring necessary right-of-way, or conducting geotechnical studies to identify potential issues that can be addressed in engineering and included in its proposed price. TransCanyon indicated that to the maximum extent practical, it secures firm, fixed-price contracts with each of its suppliers before it submits a proposal. TransCanyon indicated that this approach benefits customers by reducing TransCanyon's risk and thereby potentially reducing its required return, and also by reducing the potential for cost overruns that would exceed the cap to which TransCanyon would commit. (M-1)

TransCanyon indicated that where other developers prefer not to fix contract prices up front, they are exposed to risks that could create incentives to seek cost cap exceptions, dispute the terms of their agreed-upon cost cap, or, in the extreme case, elect not to execute the APSA at all. TransCanyon indicated that its fixed-price contracting approach would protect the ISO and customers from these risks. (M-1)

3.13.13 ISO Comparative Analysis

For purposes of the comparative analysis for this factor, the ISO has reviewed the twelve proposals of the six project sponsors to determine if there are other advantages the project sponsor or its team have for building the project that were not addressed in other parts of the selection process.

Project Design

Because there were some project design differences among the submitted proposals, the ISO undertook an analysis to determine whether any of those designs offered additional advantages or benefits over any of the other project designs.

All of the proposals except HWT's proposals 7 and 8 propose to construct the project in the configuration of alternative 1 set forth in the ISO Functional Specifications. HWT's proposals 7 and 8 seek to construct the project in the configuration of alternative 2 set forth in the ISO Functional Specifications. The ISO Functional Specifications indicated that either alternative would meet the ISO's needs. The ISO does not consider either alternative to produce material advantages or disadvantages, but alternative 2 results in much higher interconnection costs, and HWT's proposals 7 and 8 do not provide cost savings to offset those higher interconnection costs, making them significantly more costly overall than the proposals in the configuration of alternative 1.

SEGG's proposal 2 provides an SVC solution, whereas all of the other proposals rely on a STATCOM-based approach. The ISO Functional Specifications indicated that either technology could meet the ISO's needs, and all of the submitted proposals meet those needs. SEGG's SVC proposal demonstrated no material benefits that would offset its significantly higher costs than the proposals of many of the other project sponsors.

Of the proposals to construct the project in the configuration of alternative 1 using STATCOM technology, HWT, for its proposals 1 and 6, LSPGC, SEGG, for its proposal

1, SPT1, Tenaska, and TransCanyon proposed STATCOM project designs with two blocks . All of these proposals would interconnect to the Round Mountain-Table Mountain 500 kV transmission lines except for HWT's proposal 6, which would interconnect directly to PG&E's Round Mountain Substation. HWT's proposal 1 has marginally higher availability than HWT's proposal 6 and does not pose the risk that PG&E will have to underground the interconnecting transmission lines, which would significantly increase the cost of HWT's proposal 6.

HWT's proposal 2 might provide some additional benefits, such as greater availability if a portion of the project is out of service. Such potential benefits are beyond the requirements of the ISO Functional Specifications, and HWT's proposal 2 would cost materially more and add complexity to the project. Further, HWT's studies showed proposal 2 would have marginally less availability than the project design in HWT's other proposals, except for HWT's proposal 3, when all of the units are in service. Moreover, the higher costs associated with any other potential benefits would contravene the key selection factor of cost containment.

Regarding the additional services and benefits that a battery might provide, as incorporated in HWT's proposal 3, the ISO's transmission planning process did not identify a specific need for these additional services. Also, among other things, HWT did not set forth any specific proposal as to how the battery would be operated, who would operate it, or when or how it would be able to operate without adversely affecting the ISO's reliability needs for the project, and HWT did not attempt to quantify the benefits versus the added project cost. HWT did not provide any details how it might coordinate with the ISO to achieve these potential benefits if the ISO were to select its proposal 3. Further, the cost of HWT's proposal 3 is significantly higher than the costs of LSPGC's proposal and HWT's other alternative 1 STATCOM proposals, and the ISO finds no reasonable justification for selecting such a higher cost project. The significantly higher costs associated with HWT's proposal 3 would contravene the key selection factor of cost containment.

The ISO considers all of the project sponsors' project designs to satisfy the ISO Functional Specifications, and the ISO does not consider any of the project designs to be significantly better than any other in satisfying the ISO Functional Specifications or otherwise meeting the need for the project identified in the ISO's 2018-2019 transmission plan. All twelve proposals of the six project sponsors included designs that would provide the technical functionality and high availability required by the ISO Functional Specifications, and, as noted above, the ISO has concluded that any additional advantages or benefits that any of the designs might potentially provide are offset by corresponding disadvantages and drawbacks associated with that design. Consequently, the ISO does not consider any of the project designs proposed by the six project sponsors for their twelve proposals to provide any material additional advantages or benefits for purposes of meeting the specific need for this particular project.

Other Advantages

Regarding any other potential advantages or benefits of any of the twelve proposals of the six project sponsors, the ISO has determined that none of the proposals provides relevant information or identifies any particular advantages to the ISO and transmission ratepayers that the ISO has not already considered and addressed in its analysis of the more specific selection factors.

Overall Comparative Analysis

Based on its consideration of the twelve proposals of the six project sponsors, the ISO has determined that none of the proposals identifies any particular, material advantages or benefits to the ISO and transmission ratepayers. Consequently, the ISO has determined that there is no material difference among the twelve proposals of the six project sponsors with regard to 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 a number of the 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 <u>ISO Comparative Analysis</u>

The ISO's comparative analysis has considered the results of the analysis of the four 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 with regard to this project. The ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, there is no material difference among these six proposals with regard to any of the four selection factors or components. The ISO has determined that the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, are slightly better than the proposals of the other five project sponsors regarding this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, they are slightly better than the proposals of SPT1 and TransCanyon regarding the fourth selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), they are slightly better than Tenaska's proposal with regard to the third selection factor (construction and maintenance record) and the fourth selection factor, and they are slightly better than the proposals of LSPGC and SEGG, for its proposals 1 and 2, with regard to the first selection factor (financial resources) and the third selection factor, as well as the fourth selection factor, and there is no material difference among HWT's six proposals and the proposals of the other five project sponsors with regard to the other relevant selection factors or factor components.

The ISO has determined that SPT1's proposal is slightly better than TransCanyon's proposal with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the fourth selection factor, and there is no material difference between the proposals with regard to the other selection factors or factor components. The ISO has determined that SPT1's proposal is slightly better than Tenaska's proposal with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the third and fourth selection factors, and there is no material difference between the proposals with regard to the other two selection factors or factor components. The ISO has determined that SPT1's proposal is slightly better than the proposals of LSPGC and SEGG, for its proposals 1 and 2, with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the first, third, and fourth selection factors, and there is no material difference among the proposals with regard to the second selection factor component (environmental permitting experience).

The ISO has determined that TransCanyon's proposal is slightly better than Tenaska's proposal with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the third and fourth selection factors, and there is no material difference between the proposals with regard to the other two selection factors or factor components. The ISO has determined that TransCanyon's proposal is slightly better than the proposals of LSPGC and SEGG, for its proposals 1 and 2, with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the first, third, and fourth selection factors, and there is no material difference among the proposals with regard to the second selection factor component.

The ISO has determined that LSPGC's proposal is slightly better than Tenaska's proposal with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the third and fourth selection factors, which outweighs Tenaska's slight advantage regarding the first selection factor, and there is no material difference between the proposals with regard to the second selection factor component. The ISO has determined that LSPGC's proposal is slightly better than SEGG's proposals 1 and 2 with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the third and fourth selection factors, and there is no material difference among the proposals with regard to the first selection factor and second selection factor component.

The ISO has determined that Tenaska's proposal is slightly better than SEGG's proposals 1 and 2, between which there is no material difference, with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, Tenaska's proposal is slightly better with regard to the first and fourth selection factors, and there is no material difference among the proposals with regard to the second selection factor component and the third selection factor.

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 project sponsors submitted their twelve proposals that 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.

This qualification criterion considers a number of 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 with regard to this project.

Based on a detailed review of the proposals of the project sponsors regarding these factors or factor components, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, there is no material difference among these six proposals with regard to any of the three selection factors or components. The ISO has determined that the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, are slightly better than the proposals of the other five project sponsors regarding this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, they are slightly better than the proposals of SPT1 and TransCanyon regarding the third selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), they are slightly better than the proposals of LSPGC, SEGG, for its proposals 1 and 2, and Tenaska with regard to the second selection factor (construction and maintenance record) and the third selection factor, and there is no material difference among HWT's six proposals and the proposals of the other five project sponsors with regard to the other relevant selection factors or factor components.

The ISO has determined that SPT1's proposal is slightly better than TransCanyon's proposal with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the third selection factor, and there is no material difference between the proposals with regard to the other selection factors or factor components. The ISO has determined that SPT1's proposal is slightly better than the proposals of LSPGC, SEGG, for its proposals 1 and 2, and Tenaska with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the second and third selection factors, and there is no material difference among the proposals with regard to the first selection factor component (engineering experience).

The ISO has determined that TransCanyon's proposal is slightly better than the proposals of LSPGC, SEGG, for its proposals 1 and 2, and Tenaska with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the second and third selection factors, and there is no material difference among the proposals with regard to the first selection factor component.

The ISO has determined that LSPGC's proposal is slightly better than the proposals of SEGG, for its proposals 1 and 2, and Tenaska with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, it is slightly better with regard to the second and third selection factors, and there is no material difference among the proposals with regard to the first selection factor component. The ISO has determined that Tenaska's proposal is slightly better than SEGG's proposals 1 and 2, between which there is no material difference, with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, Tenaska's proposal is slightly better with regard to the third selection factor, and there is no material difference among the proposals with regard to the first selection factor component and the second selection factor.

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 ISO Comparative Analysis

The ISO previously determined and posted notice on its website that all six project sponsors submitted their twelve proposals that 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.

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 with regard to selection factor 24.5.4(e), based on the information provided and in conjunction with all the other considerations included in the ISO's analysis for the selection factor, the ISO has determined that, for this particular criterion, there is no material difference among HWT, for its six proposals, SPT1, Tenaska, and TransCanyon for their proposals and all four project sponsors and their proposals are slightly better than LSPGC and SEGG and their proposals, between which the ISO can identify no material difference, with regard to 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 project sponsors submitted their twelve proposals that 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.

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 with regard to selection factor 24.5.4(i), the ISO has determined that there is no material difference among the twelve proposals of the six project sponsors with regard to 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 project sponsors submitted their twelve proposals that 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.

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 with regard to selection factor 24.5.4(d), the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, and 7, and LSPGC and that those proposals are better than TransCanyon's proposal, which is slightly better than the proposals of HWT, for its proposal 8, and SEGG, for its proposals 1 and 2, between which there is no material difference, and which are slightly better than the proposals of SPT1 and Tenaska, between which there is no material difference, with regard to this factor overall.

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 project sponsors submitted their twelve proposals that 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.

This qualification criterion considers a number of 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 factors with regard to this project. As discussed above with regard to these three selection factors, the ISO has determined that there is no material difference among the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, with regard to this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, there is no material difference among these six proposals with regard to any of the three selection factors or components. The ISO has determined that the proposals of HWT, for its proposals 1, 2, 3, 6, 7, and 8, are slightly better than the proposals of the other five project sponsors regarding this factor because, as discussed with regard to each of the relevant individual selection factors or factor components, they are slightly better than the proposals of SPT1 and TransCanyon regarding the third selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), they are slightly better than the proposals of LSPGC, SEGG, for its proposals 1 and 2, and Tenaska with regard to the second selection factor (construction and maintenance record) and the third selection factor, and there is no material difference among HWT's six proposals and the proposals of the other five project sponsors with regard to the other relevant selection factors.

The ISO has determined that SPT1's proposal is slightly better than TransCanyon's proposal with regard to this factor because, as discussed with regard to each of the relevant individual selection factors, it is slightly better with regard to the third selection factor, and there is no material difference between the proposals with regard to the other selection factors. The ISO has determined that SPT1's proposal is slightly better than the proposals of LSPGC, SEGG, for its proposals 1 and 2, and Tenaska with regard to this factor because, as discussed with regard to each of the relevant individual selection factors, it is slightly better with regard to the second and third selection factors, and there is no material difference among the proposals with regard to the first selection factor (environmental permitting and engineering experience).

The ISO has determined that TransCanyon's proposal is slightly better than the proposals of LSPGC, SEGG, for its proposals 1 and 2, and Tenaska with regard to this factor because, as discussed with regard to each of the relevant individual selection factors, it is slightly better with regard to the second and third selection factors, and there is no material difference among the proposals with regard to the first selection factor.

The ISO has determined that LSPGC's proposal is slightly better than the proposals of SEGG, for its proposals 1 and 2, and Tenaska with regard to this factor because, as discussed with regard to each of the relevant individual selection factors, it is slightly better with regard to the second and third selection factors, and there is no material difference among the proposals with regard to the first selection factor. The ISO has determined that Tenaska's proposal is slightly better than SEGG's proposals 1 and 2, between which there is no material difference, with regard to this factor because, as discussed with regard to each of the relevant individual selection factors, Tenaska's proposal is slightly better with regard to the third selection factor, and there is no material difference among the proposals with regard to the first selection factor and the second selection factor.

3.20 Qualification Criterion 24.5.3.1(f): Commitment to Enter Into TCA and Adhere to Applicable Reliability Criteria

(Section 3 - General Project Information, QS-5)

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 HWT for Proposals 1, 2, 3, 4, 5, 6, and 7

HWT indicated that if selected by the ISO as the approved project sponsor, HWT, which would already be a PTO through the Suncrest SVC project, and which would be an affiliate of TBC, which is also a PTO, would construct and own the project and turn over the transmission element to the ISO's operational control, enter into the TCA with regard to the transmission element, and adhere to all applicable reliability criteria and comply with NERC registration requirements and NERC and WECC standards, where applicable. (QS-5)

3.20.2 Information Provided by LSPGC

LSPGC indicated that if selected as the approved project sponsor, in accordance with the APSA, LSPGC would apply to become a PTO for the purpose of turning the project over to the ISO's operational control and would enter into the TCA. LSPGC indicated that it would adhere to all applicable reliability criteria and comply with applicable NERC registration requirements and NERC and WECC standards. (QS-5)

3.20.3 Information Provided by SEGG for Proposals 1 and 2

SEGG committed to the following:
(1) That the special purpose entity that would be incorporated for this project would become a PTO for the purpose of turning the project over to the ISO's operational control;
(2) That the special purpose entity would negotiate, execute, and abide by the APSA and support its approval at FERC, to the extent FERC approval is necessary;
(3) That the special purpose entity would negotiate, execute, and abide by the TCA as well as any provisions of the ISO Tariff that pertain to a PTO; and
(4) That the special purpose entity would adhere to all applicable reliability criteria and comply with NERC registration requirements and NERC and WECC standards, where applicable. (QS-5)

3.20.4 Information Provided by SPT1

SPT1 indicated that it is prepared to execute the TCA and fully adhere to all NERC and WECC requirements and obligations. (QS 5).

3.20.5 Information Provided by Tenaska

Tenaska indicated that it commits to become a PTO for the purpose of turning the project over to the ISO's operational control by signing the TCA and by complying with all of the requirements of the TCA regarding the project. (QS-5)

3.20.6 Information Provided by TransCanyon

TransCanyon indicated that it is committed to becoming a PTO and turning the project over to the ISO's operational control through execution of the TCA. TransCanyon indicated that it has extensive experience developing, owning, and operating transmission assets in compliance with applicable NERC and WECC standards. TransCanyon indicated that it would achieve operational excellence through adherence to all applicable reliability standards and ISO requirements, as applicable, which would be facilitated by integrating projects into its existing operating platform through an O&M agreement with PacifiCorp. TransCanyon indicated that it would register with NERC as a TO, TOP, and Transmission Planner. TransCanyon indicated that PacifiCorp would perform TO and TOP functions for TransCanyon under contract but that TransCanyon would be the registered entity accountable for compliance. (QS-5)

3.20.7 ISO Comparative Analysis

The ISO previously determined and posted notice on its website that all six project sponsors submitted their twelve proposals that 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 six project sponsors 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 twelve proposals. Consequently, the ISO has determined that there is no material difference among the twelve proposals of the six project sponsors with regard to this criterion.

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 2018-2019 transmission planning process, the ISO identified a reliability-driven need for the Round Mountain 500 kV area dynamic reactive support 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 applicable tariff selection factors and qualification criteria to determine the approved project sponsor to finance, construct, own, operate, and maintain this project. HWT, for its six proposals, LSPGC, SEGG, for its two proposals, SPT1, Tenaska, and TransCanyon all submitted strong, well-prepared proposals to develop the project. The ISO was also presented with some strong cost containment proposals. The ISO re-emphasizes that it considers all project sponsors to be qualified to finance, construct, own, operate, and maintain the 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 ISO’s analysis determined that there are either no material differences or only slight differences among the project sponsors and their proposals with regard to 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 cost containment selection factor, particularly the project sponsors’ commitments to binding cost containment measures. As discussed above, this factor is one of the three key selection factors identified by the ISO at the outset of this procurement process. LSPGC proposed the strongest binding cost containment commitment proposal. In particular, it proposed more robust capital or construction cost, return on equity, and equity percentage caps that should result in lower costs and present less risk compared to the proposals of the other five project sponsors, for their eleven proposals, thus benefitting ratepayers. Further, LSPGC proposed a robust, 15-year annual revenue requirement cap that will provide lower cost, greater rate certainty, and less cost risk than the proposals of the other project sponsors. Also, the ISO projects that LSPGC’s proposal (similar to SPT1’s proposal) will result in lower interconnection costs to be incurred by

PG&E relative to the proposed locations of the projects of the other project sponsors, thus better containing the costs of the overall project, including both the part subject to competitive solicitation and the part to be constructed by PG&E.

Regarding another key selection factor, the project sponsor's proposed schedule and ability to meet that schedule, which is particularly critical due to the need for this project to address a reliability issue, LSPGC proposed a schedule that provides a substantial cushion for meeting the in-service date of June 1, 2024 specified in the ISO Functional Specifications and included a penalty for failure to meet the in-service date. These features of LSPGC's proposal combined to make it comparable to, or provide it an advantage over, the other project sponsors' proposals regarding this key selection factor.

Regarding the third key selection factor, existing rights-of-way that the project sponsor can contribute to the project, LSPGC has an option to purchase its proposed site for the project, which makes its proposal comparable to the other project sponsors' proposals.

Further, regarding this reliability project, LSPGC will have internal staff located near the project site supported by third-party emergency response providers and maintenance contractors comparably located to those of other project sponsors and with experience supporting other utilities in California.

As certain project sponsors have recognized, the area in the vicinity of Round Mountain and Table Mountain Substations can pose some challenges for project siting. LSPGC has procured a favorable site adjacent to the existing 500 kV transmission lines that limits the length of the interconnecting lines that will be necessary and avoids the shallow volcanic rock formations prevalent along the existing Round Mountain-Table Mountain 500 kV transmission line corridor. LSPGC has completed site-specific geotechnical borings, and the results indicate that the site will also minimize work and costs associated with site grading and subsurface construction.

Finally, regarding the remaining selection factors and qualification criteria, there were either no material differences or only slight differences among the project sponsors and their proposals. Regarding the factors where the proposals of other project sponsors were slightly better than LSPGC's proposal, the ISO determined that LSPGC's proposal was fully capable of successfully completing this particular project and satisfying the considerations addressed in these selection factors and qualification criteria. The rankings in many of these areas result in large part from the fact that LSPGC operates and maintains fewer transmission facilities than the affiliates of some of the other project sponsors and is not yet a signatory to the Transmission Control Agreement. However, LSPGC has an experienced STATCOM provider, construction contractor, and other service providers, and it has demonstrated successful operation and maintenance of the facilities it does have. The minor differences in these areas did not overcome LSPGC's advantage regarding cost cap and cost containment and the greater cost certainty LSPGC's proposal provides, and the ISO did not identify any undue risks. Finally, although LSPGC may not have the same financial resources as some other project sponsors, it demonstrated the ability to finance this project. For purposes of comparison, the total estimated capital cost of the Round Mountain 500 kV dynamic reactive support project and the Gates 500 kV dynamic reactive support project, for which the ISO selected LSPCG as the approved project sponsor earlier this year, is comparable to the estimated capital cost of the Harry Allen-Eldorado Transmission Line

Project, for which the ISO selected another affiliate of LS Power as the approved project sponsor and which that LSPGC affiliate financed and plans to place in service later this year.

For the foregoing reasons, the ISO has determined that LSPGC 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 for this reliability-justified project. Based on the ISO's review of the proposals and a comparative analysis with regard to all of the selection factors and qualification criteria, the ISO has determined that LSPGC's proposal is better than the proposals of HWT, for its six proposals, SEGG, for its two proposals, SPT1, Tenaska, and TransCanyon with regard to this project and the particular justification for its need. The result of this competitive solicitation process is that the ISO has selected LS Power Grid California, LLC, a wholly-owned subsidiary of LS Power Associates, L.P., as the approved project sponsor to finance, construct, own, operate, and maintain the Round Mountain 500 kV area dynamic reactive support project.

Attachment 1

Competitive Solicitation Transmission Project Sponsor Application

California ISO

Transmission Project Sponsor Proposal – Application

Contents

1 Introduction

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 application 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 (PTO) and will sign the Transmission Control Agreement (TCA) and complete a Coordinated Functional Registration (CFR). 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.

2 General Instructions

The information to be included in this 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 should 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 two documents in connection with its application. The first document is in the form of an Excel spreadsheet entitled 'CAISO Application Workbook'. This spreadsheet documents the project sponsor's proposed capital and O&M expenses, and also any proposed cost containment. The second document is a completed form of this Word document.

This Word document 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, QS-1 for Sponsor Qualifications, QP–1 for Project Qualification, E – 1 for Environmental and Public Process items, S-1 for Substation related items, 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 a project sponsor provides attachments as part of the response, the project sponsor should specify the file name of the attachment in the space provided for the response. In addition, the project sponsor should name the attached files using the following naming convention – the file name should include the unique identifier for the application item that the information responds to (e.g., E-1.a) and a description of the contents (e.g., E-1a 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 should 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 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, reactive support or series compensation station, the project sponsor should 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 should be one shapefile for each proposed transmission project and no shapefile submitted should contain more than one proposed transmission project. The proposed transmission projects are to be defined as **line** shapes. The attribute table of the shapefile should include a **"NAME" text field** that contains the name of the transmission project. Many lines may be used to define the transmission lines inside the single shapefile. Each line making up the transmission line should have the same name (the name of the transmission line). Multipart features are also acceptable. Additional fields can optionally be added. For example, a "SUBPART" field could contain a subpart name for each* *feature. (Field names should be no more than 10 characters in length and not contain any spaces or special characters as noted above.)*

*Shapefiles actually consist of several computer files that share the same filename with different file extensions. There are many file types that can be included in shapefiles that are not required, but add certain additional functionality or content. This submittal should, at a minimum, include the following four files: **name.shp**, **name.shx**, **name.dbf** and **name.prj**. The first three are the standard minimum for a shapefile and the last one is a projection file that documents the projection used in a standard way that can be read by GIS systems.*

The file name should 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 should be zipped together in a single "zip" file with the same name as the shapefile. The following are some examples of zip file names.

Transmission Project Name	*Example Zip File Name*
Delaney-Colorado River	*Delaney_Colorado_River.zip*
Harry Allen/Eldorado	*Harry_Allen_Eldorado.zip*

Example: ***Delaney_Colorado_River.zip*** *contains these files (theshapefile):*
Delaney_Colorado_River.shp ***Delaney_Colorado_River.shx***
Delaney_Colorado_River.dbf ***Delaney_Colorado_River.prj***

Submit the zip file containing the shapefiles along with your application and supporting documents (preferably on CDs or DVDs. See note below regarding submittal on CD or DVD.).

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. If the project sponsor believes that any item of the application is not applicable to its project proposal, it may indicate "N/A" but should provide a brief reason why it believes it is not applicable.

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, regulatory and reliability requirements.

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 should also indicate how its response would change depending on how many of its proposals are approved by the ISO. For example, the project sponsor should 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 should clearly identify the single proposal that it wishes the ISO to evaluate.

The application includes an officer certification form (Section 12) 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.

Project sponsors should note that the maximum size of an e-mail submitted to the ISO should 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 should 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 Word document and associated attachments, and the Excel spreadsheet) 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 the application 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 $75,000 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 13 of this application.

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.

3 Project Sponsor, Name and Qualifications

Project Sponsor Name:

Response: (Enter Project Sponsor Company Name)

Project Description:

Response: (Enter Project Description)

Submittal Date:

Response: (Enter Submittal Date)

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 should include but not be limited to the following information:

- 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.
- The entity or entities that will service the debt associated with the design, procurement, construction, and placing the project in service and the debt carried after commercial operation.
- The entity or entities that will perform the siting, permitting, engineering, procurement, construction and placing the project into operation; also describe if this is to be accomplished through a turn-key EPC contract or some other manner and the type of relationship to be used (e.g. fixed price contract, in-house staff, etc.)
- The entity or entities that will perform maintenance and operation of the project; also describe the resources to be used for carrying out this responsibility (e.g. in-house staff, subsidiary, affiliate, contracted to a separate O&M company, etc.)

Response:

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. 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).

Project Sponsor Qualification
The project sponsor must demonstrate that it meets the project sponsor qualification criteria for the needed transmission element by providing responses to the following five items (QS-1, QS-2, QS-3, QS-4, QS-5) that relate to the qualification of the project sponsor. Note that when providing these responses, the project sponsor may refer to information that has been provided in other sections of this application for additional information and support. However, the following five responses should provide a complete demonstration of qualification – either through the responses directly or by including references in the responses to material provided in responses to other items in this application.
Describe and demonstrate how:

QS-1. The project sponsor has assembled a sufficiently-sized team (or planned team) with the manpower, equipment, knowledge, and skill required to undertake the design, construction, operation, and maintenance of the transmission solution.

Response:

QS-2. The project sponsor and its team (or planned team) will have sufficient financial resources; for example, 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.

Response:

QS-3. The project sponsor (1) has a proposed schedule for development and completion of the transmission solution consistent with needed in service date identified by the ISO and (2) has the ability to meet that schedule.

Response:

QS-4. The project sponsor and its team (or planned team) have the necessary technical and engineering qualifications and experience to undertake the design, construction, operation and maintenance of the transmission solution.

Response:

QS-5. 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:

Proposal Qualification

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. Note: when providing these responses, the applicant may refer to information that has been provided in other sections of this application for additional information and support. However, the following two responses should provide a complete demonstration or qualification – either through the two responses directly or by including references in the two responses to material provided in responses to other items in this 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:

4 Past Projects, Project Management and Cost Containment

Project Sponsor's Past Project Information

P - 1. Provide a list of all transmission lines above 200 kV (if this proposed project includes transmission line facilities and substations above 200 kV, including reactive support and series compensation installations (if this proposed project includes substation and/or reactive support or series compensation facilities) which the project sponsor or the project sponsor's team or planned team has constructed, financed, owned, operated and/or maintained within the last five years. List the transmission line projects separately from the substation, reactive support and series compensation projects. Note: if the project sponsor does not have experience constructing transmission facilities over 200 kV, but does have experience constructing facilities at lower transmission voltages, it may include this experience. For each project include the following in the table provided below:

1) For transmission line projects, provide a description of the line including type of construction (underground, overhead, steel pole, etc.). For substation projects include the number of breakers by voltage and the bus arrangement (BAAH, DBDB, etc.) and, if applicable, reactive support or series compensation segments and voltage.
2) location (country, state, city),
3) voltage level(s),
4) length,
5) nominal rating of transmission line, reactive support, series compensation and total MVA of substation transformers,
6) capital cost,
7) year placed in service, and
8) Whether the project sponsor performed each of the following functions "in-house" (*i.e*. the project sponsor actually performed the work as opposed to providing oversight) for the projects listed - financing (F), designing (D), siting (S), constructing (C), operating (O) and maintaining (M) the line or substation. List all areas that apply. For example, if the project Sponsor had responsibility for performing only the Construction, Operation and Maintenance on a project, then a C, O, M would be entered in that cell in the table.

P-1 Responses - List of Past Projects

P-1 Transmission Line Projects							
(1)Project Description	(2)Location (Country, City(ies)	(3)Voltage Level(s)	(4)Length (4) (Miles)	(5)Nominal Rating (MVA)	(6)Capital Cost (Million USD)	(7)Date Placed in Service(7)	(8)Project Sponsor Performed Responsibility (F, D, S, C, O, M)
P-1 Substation Projects (including Reactive Support and Series Compensation)							
(1)Project Description	(2)Location (Country, City(ies))	(3)Voltage Level(s)	(4)Length (Miles) and Number of Circuit Breakers	(5)Nominal Rating of All Transformers (MVA) or Reactive Support or Series Compensation (MVAR)	(6)Capital Cost (Million USD)	(7)Date Placed in Service	(8)Project Sponsor Performed Responsibility (F, D, S, C, O, M)

Project Liability Protection

P - 2. 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:

Project Management, Historical Performance Related

P - 3. For the transmission and substation projects included in the response to P-1, provide the following:

(a) Brief overall project description.

(b) Planned project in-service date at the time of project approval, and the actual project in-service date of project completion. Explain the circumstances for a project that did not meet the planned in-service date.

(c) Overall cost summary.

(d) Provide the initial budget for the project at the time the project was approved, and the final actual project cost. Explain the circumstances for any project budget variances that exceeded the initial budget.

(e) Major issues confronted and resolved during project.

(f) Typical management progress reports for the project.

(g) Other specific materials that reflect project management skills for an actual project.

(h) If the project sponsor is an SPE, please provide the experience of the parent organization(s) for similar projects.

Response:

Project Management, Project Related

P - 4. Provide a general description of the proposed approach to project management and scheduling (PM&S) for the transmission element.

Response:

P - 5. Provide the proposed management structure, organization, authority levels, the project sponsor's relationship to each of the contractors, and resources committed to PM&S for the full scope of the project, including relevant experience and capability for the proposed Project Manager (PM) and other relevant decision-makers for the project. If the sponsor does not have a team in place, please provide your plan to meet these requirements.

Response:

P - 6. 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;
- 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 start date in the schedule was delayed by 6 months.

Response:

P - 7. For the proposed project, identify the major risks and obstacles to successful project completion on schedule and within cost budget and identify proposed mitigations to minimize the risks. Describe all actions that the project sponsor will take to keep the project on schedule and within budget in light of the major risks identified.

If the project sponsor is sponsoring more than one project, the project sponsor should 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 - 8. Indicate all of the state and federal governmental and/or regulatory agencies that the project sponsor expects to interact with during the course of developing, approving and constructing the project.

For each governmental or regulatory agency listed,

a. Explain the specific aspect of the project that the agency will need to approve or otherwise be involved;

b. Indicate the agency's ability to impose binding cost control measures or cost caps on the project;

c. Describe the project sponsor's experience working with that agency for at least the last 5 years.

Response:

5 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. Describe the financial and legal structure of the project sponsor, including type of corporation if a corporation, or type of entity if it is a Special Purpose Entity (SPE; e.g., project financed LLC) created explicitly for the proposed project. 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 this application, please (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, please 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. 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. 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 a Special Purpose Entity (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.

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 response to P-1 that are similar in type and size to (or larger than) the transmission element and/or substation proposed in this application. Include the following in your response and use the table provided below:

1) Project description
2) Financing structure (e.g. LLC vs. corporate, etc.)
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. 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 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:

F - 14. For financing sources other than the capital markets, describe the benefits to ratepayers and others of your proposed financing source(s). This should include the projected cost of the financing sources.

Response:

6 Environment 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, obtain rights of way (ROW) or other land acquisition for the project, 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:

Environmental Team and Experience

E - 2. Provide a list of and description of the firm or group who will be responsible for the siting, land acquisition and permitting aspects of the project. Specify the relationship between the Project Sponsor and these firms or groups (e.g. owned by the project sponsor, under contract to Project Sponsor, a division or department of the project sponsor, etc.). For each of the firms or groups listed, indicate their individual responsibilities and provide a resume for each lead individual. If the sponsor does not have a team assembled, provide your plan to meet these requirements. If you plan to use a firm and have not selected one yet, provide the requested information for the firms you are considering.

Response:

E - 3. Complete a section of the table below for each firm or group listed in E-2, whether in place or planned. For each of the firms or groups listed provide a list of all transmission substation projects in which they have had the responsibility for siting, land acquisition and/or permitting aspects of the project within the last five years. Include the following information:

1) Firm or group name
2) Summary of the project (purpose, include voltage level(s), capacity, number of breakers and arrangement)
3) The firm or group's responsibility on the project (e.g. siting, permitting, ROW acquisition, etc.)
4) Year project was completed
5) Capital cost of the project in US Dollars (millions)
6) Client for whom the firm or group worked

E-3 (1)Firm or Group Name [Use for first firm or group]				
(2)Project Summary	(3)Firm/Group Responsibility	(4)Year Comp	(5)Capital Cost (USD) (M)	(6)Client

(1)Firm or Group Name [Use for second firm or group if needed]				
(2)Project Summary	(3)Firm/Group Responsibility	(4)Year Comp	(5)Capital Cost (USD) (M)	(6)Client
(1)Firm or Group Name [Use for third firm or group if needed]				
(2)Project Summary	(3)Firm/Group Responsibility	(4)Year Comp	(5)Capital Cost (USD) (M)	(6)Client

E - 4. For each firm or group listed in E-2, indicate what work the project sponsor has completed in the past using these firms for similar areas of responsibilities.

Response:

Permitting

E - 5. 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. EPA Clean Water Act, USACOE Section 401- 404, USFWS Biological Opinion required, etc.

Response:

E - 6. Using your best estimate, indicate whether any state discretionary permit(s) will be required and the type of permit to be filed (e.g. incidental take permit, water quality Section 401, etc.)

Response:

E - 7. Provide a generalized schedule of the permit activities anticipated, their dependencies and timelines.

Response:

E - 8. Indicate if any federal land (for example Forest Service, BLM, etc.) is proposed to be crossed, and if a NEPA (National Environmental Policy Act) environmental process is required.

Response:

E - 9. 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[11] (BMPs) 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.

Response:

c. Provide a list of Applicant Proposed Measures (APMs) 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 check list.

Response:

d. Indicate if you expect to perform any public outreach (e.g. open houses, project hotline number, project update mailings etc.) and describe the planned outreach program.

Response:

Transmission or Substation ROW Acquisition

[11] BMPs, which are environmental industry standard terminology, are the applicant'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/injury reporting, community involvement programs involving both the local elected officials and the immediate community that will be impacted by the proposed project.

E - 10. 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, dismissed and justification for preferred.

Response:

E - 11. 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:

E - 12. Provide an indication of whether the project sponsor has eminent domain authority. If the applicant 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:

E - 13. Indicate whether the project sponsor has any existing ROW or substations or plans to acquire existing ROWs or substation property from another party 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 / or risks associated with using the existing ROW (for example negotiating additional land rights or the potential of "overburdening" existing easements, etc.). 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:

E - 14. Provide information describing all transmission lines that were constructed in at least the last 5 years for which the project sponsor or its environmental contractor (designated to complete the environmental and public processes for this proposed project) completed the environmental and public processes associated with the project. The information provided should include:

a. Transmission line routing and length of routes

Response:

b. Rights of way acquired

Response:

c. Federal and State permits acquired to construct the project

Response:

d. Environmental processes and results as follows:

i. Provide Federal NEPA or State environmental review determinations if applicable. For projects in California provide CEQA filing history and link to agency web site of the final adjudication or Cal State Clearinghouse number;

Response:

ii. Provide a list of post project mitigation agreements for endangered species impact mitigation; and

Response:

iii. Provide a list of any management plans instituted to comply with Fed/State permits authorizing construction.

Response:

E - 15. Provide information describing all transmission substation projects that were constructed in at least the last 5 years in which the project sponsor or its contractor (designated to complete the environmental and public processes for this proposed project) completed the environmental and public processes. The information provided should include (for multiple projects, duplicate the headings (a-d) and Response boxes for each project):

a. Substation location

Response:

b. Land acquired

Response:

c. Federal and State permits acquired to construct the project

Response:

d. Environmental processes and results as follows:

Response:

i. Provide Federal NEPA or State environmental review determinations if applicable. For projects in California provide CEQA filing history and link to agency web site of the final adjudication or Cal State Clearinghouse number;

Response:

ii. Provide a list of post project mitigation agreements for endangered species impact mitigation; and

Response:

iii. Provide list of any management plans instituted to comply with Fed/State permits authorizing construction.

Response:

E - 16. Provide information related only to transmission line, reactive support, series compensation and substation siting, permits, rights of way and land acquisition for at least the last 5 years. If the applicant is an SPE, provide information on the parent organization(s) for similar projects. Provide:

a. A description of any project Notice of Violation (NOV) in the last 5 years

Response:

b. Fines levied by the Project approval authority and any other discretionary/ministerial authority

Response:

c. Remediation actions taken to avoid future violations

Response:

d. A summary of law violations by the project sponsor found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general

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 is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws

Response:

7 Substation

The S items listed below should only be completed if the propose transmission solution contains a substation or facilities similar to a substation (e.g. synchronous condenser, STATCOM, etc.).

S - 1. For each substation or reactive control element that is included as part of your proposed project, provide the location, 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. Provide a list and a description of the firms or groups who will be responsible for substation, reactive support or series compensation facility design and construction; include information for firms or groups who will perform any required system studies (e.g. SSR studies). Indicate if the work will be done by the Applicant's personnel, specific firms, firms pre-approved by the Applicant or a combination. Specify the relationship between the project sponsor and these firms or groups (e.g. owned by the project sponsor, under contract to project sponsor, a division or department of the project sponsor, etc.). For each of the firms or groups listed indicate their individual responsibilities on the proposed project (e.g. design, construction, etc.) and provide a resume for the lead individual for each group or firm. If this information is not available provide your plan to meet these requirements. If you plan to use a firm and have not selected one yet, provide the requested information for the firms you are considering.

Response:

S – 3. Complete a section of the table below for each firm or group listed in S-2, whether in place or planned. For each firm or group listed provide a list of all transmission substation, reactive support and/or series compensation projects they have constructed within at least the last five years.

1. Firm or group name
2. Summary of the project (purpose, include voltage level(s), capacity, number of breakers and arrangement)
3. The firm or group's responsibility on the project (e.g. engineering, construction, procurement, etc.)
4. Year project was completed
5. Capital cost of the project in US Dollars (million)

S-3. (1) Firm or Group Name [Use for first firm or group]			
(2) Project Summary	(3)Firm/Group Responsibility	(4)Year Completed	(5)Capital Cost (USD) (M)

(1) Firm or Group Name [Use for second firm or group if needed]			
(2) Project Summary	(3)Firm/Group Responsibility	(4)Year Completed	(5)Capital Cost (USD) (M)
(1) Firm or Group Name [Use for third firm or group if needed]			
(2) Project Summary	(3)Firm/Group Responsibility	(4)Year Completed	(5)Capital Cost (USD) (M)

S – 4. For each firm or group listed in response to S-2, indicate what previous work (list projects or activities) the project sponsor has completed using these firms. In particular, list any previous work that is similar to the work that the firm or group will be responsible for on the project.

Response:

S – 5. For each proposed substation, reactive support and/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 mud slide considerations, etc.).

Response:

S – 6. For each proposed substation, reactive support and/or series compensation installation, provide the basic parameters for the installation - primary and secondary voltage, BIL[12], initial design power capacity and final design power capacity (if developed in stages).

Response:

S – 7. For each proposed substation, reactive support and/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, etc. Provide a complete list of state specific requirements for each US state that the project will be located in (e.g. California and other state specific requirements if part of the project or the entire project is located outside California).

Response:

S – 8. For each proposed substation, reactive support and/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,
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 – 9. For each proposed substation, reactive support and/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:

[12] 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.

S – 10. For each proposed substation, reactive support and/or series compensation installation, describe the SCADA incorporated in the design; list the data that will be provided to the ISO; list the control functions that will be included, and which entity will be in control of the devices.

Response:

S – 11. For each proposed substation, reactive support and/or series compensation installation, describe the physical security criteria and specific security measures that will be incorporated in the final facility design. Also, describe the oil containment criteria and specific containment measures that will be incorporated in the final design.

Response:

8 Transmission Line

The T 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.
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 a description of the firms or groups who will be responsible for the transmission line design and construction. Indicate if the work will be done by the Applicant's personnel, specific firms, firms pre-approved by the Applicant or a combination. Specify the relationship between the Project Sponsor and these firms or groups (e.g. owned by the Project Sponsor, under contract to project sponsor, a division or department of the project sponsor, etc.). For each of the firms or groups listed indicate their individual responsibilities on the proposed project (e.g. design, construction, etc.) and provide a resume for the lead individual for each group or firm.

Specify the relationship between the project sponsor and these firms or groups (e.g. owned by the project sponsor, under contract to project sponsor, etc.) If this information is not currently available, please provide your plan to meet these requirements. If you plan to use a firm and have not selected one yet, provide the requested information for the firms you are considering.

Response:

T - 3. Complete a section of the table below for each firm or group listed in T-2, whether in place or planned. For each of the firms or groups listed, provide a list of all transmission line projects above 200 kV that they have designed or constructed within the last five years and the following information:

6. Firm or group name
7. Summary of the project purpose, include voltage level(s), capacity, conductor, structure type, and mileage. If both overhead and underground transmission was included separate info into overhead and underground.
8. The firm or group's responsibility on the project (e.g. engineering, construction, procurement, etc.)
9. Year project was completed
10. Capital cost of the project in US Dollars (million)
11. Client – who the firm or group worked for on the project

T-3 (1)Firm or Group Name [Use for first firm or group]				
(2)Project Summary	**(3)Firm/Group Responsibility**	**(4)Year Comp**	**(5)Capital Cost (USD) (M)**	**(6)Client**
(1)Firm or Group Name [Use for second firm or group]				
(2)Project Summary	**(3)Firm/Group Responsibility**	**(4)Year Comp**	**(5)Capital Cost (USD) (M)**	**(6)Client**

California ISO

T - 4. For each firm or group listed, indicate what previous work the project sponsor has completed using these firms for similar areas of responsibility.

Response:

T - 5. 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 - 6. 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 - 7. 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, etc. 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 - 8. 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 - 9. Provide the following information in the table provided for any proposed overhead transmission line:

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 GO95 Grade of Construction.

i. Provide NESC and/or GO95 Loading Corridor Separation.

j. Identify all existing or permitted transmission lines, including voltage, structure type, and separation, located in the same corridor as the proposed project. Identify the criteria used to establish the corridor separation.

T-9 Item	**Response**
a	
b	
c	
d	
e	
f	
g	
h	
i	
j	

T - 10. For any proposed overhead 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 - 11. 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.

Corridor Separation

h. Identify all existing or permitted transmission lines, including voltage, structure type, and separation, located in the same corridor as the proposed project.

T-11 Item	**Response**
a	
b	
c	
d	
e	
f	
g	
h	

T - 12. For any proposed underground transmission sections 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 - 13. 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, etc.) 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, etc.).
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-13 Item	**Response**
a	
b	
c	
d	
e	

9 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, to provide material to contractors, quality, and expediting.

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, expected helicopter work, etc.)

Response:

C-8 Identify any construction related fines incurred by the project sponsor for projects completed during the last five years. If the project sponsor is an SPE, provide the information for the parent organization(s).

Response:

10 Operation and Maintenance

Operation and Maintenance Team and Operating and Maintenance Record

O-1 Provide a chart of the project sponsor's proposed organizations showing the reporting relationships of the maintenance and operations organizations including compliance management functions. Describe the roles and responsibilities of the maintenance and operations organizations, including operating jurisdictions as they relate to the proposed project. Identify the planned location of those responsible for operation and maintenance 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 organization that are planned to accommodate the proposed project. Please provide any contract you have with a third-party to provide operation and/or maintenance services for the project.

Response:

O-2 Provide resumes describing the qualifications and experience of key management personnel in the proposed maintenance and operating organizations. Relate each resume to a position on the organization chart provided in response to O-1.

Response:

O-3 Describe the experience over the past 5 years with operating and maintaining all transmission facilities by the project sponsor or project sponsor team members. Describe the role played by the proposed project team members in operating and maintaining those facilities.

Response:

O-4 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-5 Describe the project sponsor's training program for operations and maintenance personnel. Include initial and continuing education requirements for maintaining qualifications for classifications with operation and maintenance responsibilities (e.g. what are the training and certification requirements for operators, linemen and substation electricians?). Identify training resources used.

Response:

Maintenance Practices

O-6 Describe the project sponsor's capability and experience 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 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 these ISO Transmission Maintenance Standards. The effectiveness of each PTO's Maintenance Practices will be gauged through the Availability performance monitoring system. Each PTO's adherence to its Maintenance Practices will be assessed through an ISO review. (TCA Appendix C Maintenance Procedure 4).

Response:

O-7 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:

O-8 Provide information, notices or reports regarding the project sponsor's experience with implementation and compliance with its standards for inspection, maintenance, repair and replacement of similar facilities. Include audit reports or regulatory filings.

Response:

O-9 Describe the project sponsor's capability and experience that will enable it to provide its Availability Measures in accordance with TCA Appendix C 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 and experience.

Response:

O-10 Would adding the project to the ISO controlled grid require any changes or exceptions to the provisions of the TCA? If "yes", describe.

Response:

Operating Practices

O-11 Identify the NERC functions for which the project sponsor has registered or intends to become registered related to the proposed project.

Response:

O-12 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 firm and have not selected one yet, provide the requested information for the firms you are considering. Describe how the project sponsor will ensure compliance with the reliability Standard(s) or requirement(s) associated with these functions. Provide any contract you have with a third-party to perform NERC functions.

Response:

O-13 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 5.1.6. Explain any.

Response:

O-14 Provide information demonstrating that the project sponsor, or its intended contractor or contractors as identified in O-12, has been in compliance with the Applicable Reliability Standards for all transmission facilities that it owns, operates, and or maintains. This could include information for facilities outside the ISO controlled grid and should include available NERC compliance audit results and any notices of violation. Provide information describing the amount of transmission facilities subject to NERC compliance, e.g. miles of line by voltage class, number of substations by voltage class. If the project sponsor does not have experience with transmission facilities subject to NERC Standard, provide information demonstrating compliance with standards that do apply to those facilities and the amount of facilities subject to such compliance.

Response:

O-15 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 CAISO and other PTOs, and describe expected differences if any. Existing agreements are available on the CAISO website.

Response:

O-16 Describe the applicable agreements that will define the Transmission Operator responsibilities and authority with respect to 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-17 Describe how the project sponsor will meet the requirement that Transmission Operators 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 4.3.

Response:

O-18 Describe the project sponsor's (its team or planned team) capability and experience that will enable it to comply with the activities required by TCA 6.1. Physical Operation of Facilities. (Operation, ISO Operating Orders, Duty of Care, Outages, Return to Service and Written Report), TCA 6.3 Other Responsibilities and TCA 7 Operations and Maintenance. (Scheduled Maintenance, Exercise of Contractual Rights and Unscheduled Maintenance).

Response:

O-19 Describe the project sponsor's capability (for its team or its planned team) and experience that will enable it to comply with the activities required by TCA 9.2. Management of Emergencies by Participating TOs and 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-20 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 the ISO's Operational Control are subject, together with any documents creating such Encumbrances and any instructions on how to implement Encumbrances and Entitlements in accordance with the TCA 6.4.2.

Response:

O-21 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:

11 Miscellaneous

M-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 application.

Response:

12 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 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 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 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: ______________________________

13 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 should be made payable to the CAISO.**

California ISO
Attn: Julie Balch
Grid Assets
P.O. Box 639014
Folsom, CA 95763-9014

Overnight Address
California ISO
Attn: Julie Balch
Grid Assets
250 Outcropping Way
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

Approval History

Approval Date: April 17, 2019

Effective Date: April 17, 2019

Application Owner: Stephen Rutty

Application Owner's Title: Director, Grid Assets

Revision History

Version	Date	Description
6	4/17/2019	General update
5	5-10-2016	General update and revised to address stakeholder comments.
4	4-07-2014	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

Attachment 2

CALIFORNIA ISO APPLICATION WORKBOOK INSTRUCTIONS TAB IN EXCEL SPREADSHEET

CALIFORNIA ISO APPLICATION WORKBOOK

INSTRUCTIONS TAB IN EXCEL SPREADSHEET

Section CC – Costs and Cost Containment

0. General Instructions
a. Please provide all responses to Question CC-0 in the tab (worksheet) titled "0-General Inputs".
b. Please provide the name(s) of the project sponsor(s).
c. Please provide the ownership shares of the project sponsor(s).
d. Please provide the planned construction period, identifying the month and year construction will begin. Please also provide the month and year that commercial operation will begin.
e. Please provide the useful life of the constructed project.
f. The inflation rate is provided by the CAISO and is not subject to change.
1. Capital Costs
a. Please provide all responses to Question CC-1 in the tab (worksheet) titled "1-Capital Costs".
b. Please provide, in nominal dollars, capital expenditure estimates by month for each category of expenditure that the project sponsor(s) plans to seek FERC approval for recovery. Please aggregate costs into the categories most relevant to development of the proposed project. For projects with transmission and substation components, the costs for each component should be clearly separated. Examples include, but are not limited to: environmental, right-of-way, engineering, civil works, materials, equipment, construction, construction management, etc. Capital expenditure estimates should include all capital expenditures, including any ongoing expenditures, for which the project sponsor(s) plans to seek FERC approval for recovery.
i. The inflation rate is provided by the CAISO and is not subject to change.
ii. Please provide assumptions for the capital expenditure estimate (e.g. design assumptions, weather, manpower needed and work schedule, # of hours per day, construction area access, planned outages needed, etc.) and any sensitivity analyses performed in developing the cost estimate. (Note: all assumptions and sensitivities need to be documented). If the details are voluminous, please provide in an attachment.

2. Operations and Maintenance Costs
a. Please provide all responses to Question CC-2 in the tab (worksheet) titled "2-O&M Costs".
b. Please provide, in nominal dollars, estimated operation and maintenance (O&M) expenses and estimated Administrative and General (A&G) expenses, by year and by FERC account, for all such expenses that the project sponsor(s) plans to seek FERC approval for recovery. Please exclude property taxes from O&M expense estimates.
i. The inflation rate is provided by the CAISO and is not subject to change.
ii. Please describe each proposed maintenance activity and their frequencies planned over the life of the facilities.
3. Cost of Capital
a. Please provide all responses to Question CC-3 in the tab (worksheet) titled "3-Cost of Capital".
b. Please provide the assumed capital structure which the project sponsor plans to propose at FERC.
c. Please provide the assumed interest rates on debt and expected return on preferred/common equity. Please describe the assumptions regarding lender (e.g., bank, corporate parent, structure, term). Please provide any supporting documentation showing the basis for the assumed interest rate.
4. Regulatory Treatment
a. Please provide all responses to Question CC-4 in the tab (worksheet) titled "4-Regulatory Treatment".
b. Please indicate whether the project sponsor(s) intends to seek, as a FERC incentive, cash recovery on CWIP ("CWIP in rate base").
c. Please provide, in nominal dollars, the estimated monthly AFUDC for the project, even if the project sponsor(s) intends to pursue CWIP in rate base.

d. Please provide, in nominal dollars, the total monthly costs that are expected to be capitalized in rate base from Capital Costs and AFUDC, beginning with the first month such costs are to be incurred, and continuing through the commercial operation date. Please assume for this calculation that AFUDC is accrued on CWIP, even if the project sponsor(s) intends to seek a current cash return on CWIP during the construction period.
e. Please provide the net transmission plant (outstanding rate base) in nominal dollars. Please provide any rate base adjustments that apply.
5. Depreciation
a. Please provide all responses to Question CC-5 in the tab (worksheet) titled "5-Depreciation".
b. Please provide the book, federal tax, and state tax depreciation schedules for capital expenditures used in the calculation of the project sponsor's Revenue Requirement (Question CC-8). For purposes of this section, please assume construction-period interest expenses and return on equity are capitalized in AFUDC.
i. Please provide the method you applied to each of these depreciation estimates (e.g. 15 year MACRS, Half year convention).
ii. Please provide any bonus depreciation that the plant will eligible for, if any.
c. Please provide the book, federal tax, and state tax depreciation schedules for ongoing capital expenditures used in the calculation of the project sponsor’s Revenue Requirement (Question CC-8). For purposes of this section, please assume construction-period interest expenses and return on equity are capitalized in AFUDC.
i. Please confirm that any ongoing capital expenditures were depreciated under the same methodology as those of the constructed project. If not, please describe any differences.
ii. Please provide the method you applied to each of these depreciation estimates (e.g. 15 year MACRS, Half year convention).

6. Taxes
a. Please provide all responses to Question CC-6 in the Project Cost Template, "6-Taxes" tab (worksheet).
b. Please provide the federal and state income tax rates that the project sponsor assumes would be applicable to the project as well as the % of federal tax that is deductible for state purposes and the % of ownership that is tax exempt, if any. Please provide a description of any other income-based or revenue-based taxes that may be applicable.
c. Please provide the annual effective property tax rate that the project sponsor believes would be applicable to the project, as well as any other taxes that are applied on net plant. Please provide the assumptions that underlie the property tax rate estimate, such as county rates and assessment ratios.
7. Revenue Requirement
a. Please provide all responses to Question CC-7 in the tab (worksheet) titled "7-Revenue Requirement".
b. Please provide, in nominal dollars, the project sponsor’s estimated annual revenue requirement each year from commercial operation through the book life of the plant. Please include the complete build up of the revenue requirement including, at least: depreciation, cost of debt, return on equity, federal and state income tax, other income-based or revenue-based tax, property tax, and other costs. Please indicate any assumptions that have not been previously stated.
c. Please provide an Excel-based workbook with all supporting formulas (visible, active, and unlocked) that provides a bottom up calculation of the project sponsor’s annual revenue requirement (“ARR”). The workbook should calculate the ARR at least annually, and preferably monthly through the construction period. All relevant hard-code values should be clearly sourced.
8. Cost Containment
Note that any and all cost containment measures are optional.
a. Please provide all responses to Question CC-8 in the tab (worksheet) titled "8-Cost Containment".
b. Please indicate whether the project sponsor(s) is (are) proposing a binding cap on capital expenditures.

i. Please provide, in nominal dollars, the project sponsor’s proposed binding cap on capital expenditures, if applicable.
ii. Please indicate if all costs prior to the commercial operation date are included in the cost cap. If not, please explain.
iii. Please indicate if AFUDC is included in the cap. If not, please explain if AFUDC would be otherwise limited or capped.
iv. Please describe any conditions under which the capital expenditures and/or AFUDC cap would not apply.
v. Please indicate if the cap includes a variable, fixed, or capped inflation rate. Please describe.
c. Please indicate whether the project sponsor(s) is (are) proposing a binding cap on TOTAL O&M expenditures.
i. Please provide, in nominal dollars, the project sponsor’s proposed binding cap on operations and maintenance expenses, if applicable.
ii. Please indicate whether all O&M expenses (including A&G and all O&M expense categories under FERC's Uniform System of Accounts) are included under the cost cap. If not, please identify those costs not covered by the cap.
iii. Please describe the length of any proposed cap and any conditions under which the cost cap would not apply.
d. Please indicate whether the project sponsor(s) is (are) proposing a binding cap on ANNUAL O&M expenditures.
i. Please provide, in nominal dollars, the project sponsor’s proposed binding cap on annual operations and maintenance expenses by year, if applicable.
ii. Please indicate whether all O&M expenses (including A&G and all O&M expense categories under FERC's Uniform System of Accounts) are included under the cost cap. If not, please identify those costs not covered by the cap.
iii. Please describe the length of any proposed cap and any conditions under which the cost cap would not apply.
e. Please indicate whether the project sponsor(s) is (are) proposing a binding cap on ROE.

i. Please provide an annual cap on ROE by year, if applicable.
ii. Please describe whether and how any ROE and / or debt cap would apply to the determination of the AFUDC rate.
iii. Please explain whether the ROE cap includes any ROE incentives. If FERC were to approve an allowable ROE higher than the cap, would the cap still apply?
iv. Please describe the length of any proposed cap and any conditions under which the cost cap would not apply.
f. Please indicate whether the project sponsor(s) is (are) proposing a binding cap on Equity %.
i. Please provide an annual cap on Equity % by year, if applicable.
ii. Please describe whether and how any Equity % cap would apply to the determination of the AFUDC rate.
iii. Please describe the length of any proposed cap and any conditions under which the cost cap would not apply.
g. Please indicate whether the project sponsor(s) is (are) proposing a binding cap on the annual revenue requirement.
i. Please provide, in nominal dollars, the project sponsor’s proposed binding cap on annual revenue requirement by year, if applicable.
ii. Please indicate whether all revenue requirement items are included under the cost cap. If not, please identify those costs not covered by the cap.
iii. Please describe the length of any proposed cap and any conditions under which the cost cap would not apply.
h. Other Cost Cap Information
i. Please describe any other cost containment measures not otherwise covered above.
9. Other Information

CALIFORNIA ISO APPLICATION WORKBOOK

INSTRUCTIONS TAB IN EXCEL SPREADSHEET

a. Please provide all responses to Question CC-9 in the tab (worksheet) titled "9-Other Information".
b. Provide any cost or cost containment information not otherwise covered in this Project Cost Template.