UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Technology Solutions, LLC and Western Grid Development, LLC,	)	
Complainants,	)	
v.	)	**Docket No. EL11-8-000**
California Independent System Operator Corporation,	)	
Respondent.	)	

ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO COMPLAINT

The California Independent System Operator Corporation ("ISO") hereby submits its answer ("Answer") to the complaint ("Complaint") filed in this proceeding by Transmission Technology Solutions, LLC ("TTS") and Western Grid Development, LLC ("WGD") (together, "Complainants").[1] The Complaint alleges that the ISO's has failed to comply with the requirements of the transmission planning process set forth in former section 24 of the ISO tariff (as in effect at the time of the complaint) in evaluating transmission project proposals submitted by the Complainants for consideration in the ISO's 2008-2009 and 2009-2010 transmission planning cycles.[2] As explained herein, the ISO's

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1 The ISO submits this filing pursuant to Pursuant to Rules 206(f) and 213 of the Commission's Rules of Practice and Procedure ,18 C.F.R. §§ 385.206(f), 385.213 (2010), and the Notice of Extension of Time issued in this proceeding on December 3, 2010.

2 Except where otherwise noted, all tariff references in this Answer are to the transmission planning tariff provisions that were in effect prior to the revised transmission planning process which the Commission approved on December 16, 2010. These were the tariff provisions that were in effect when the TTS and WGD submitted their project proposals.

evaluation of these proposals has been fully consistent with the applicable tariff requirements, and the ISO has approved cost-effective solutions for resolving the reliability needs identified by the ISO that were the subject of the TTS and WGD project proposals. Indeed, using TTS' and WGD's own biased (and flawed) cost comparison numbers (which are based on a net present value ("NPV") of the WGD projects' yearly revenue requirement, approval of WGD's proposed projects alone would impose a minimum of $249 million in additional costs on ISO ratepayers, above and beyond the costs of the projects that the ISO approved (or for which the ISO found no project was needed. TTS' and WGD's claims are based on incorrect interpretations of ISO documents, factual inaccuracies, numerous conclusory allegations, and an extremely flawed cost comparison analysis. Moreover, the remedies requested by the Complainants would require the ISO to violate provisions concerning the construction of reliability-driven transmission projects that have been in the ISO tariff since the ISO commenced operations and which were recently affirmed by the Commission. Finally, under the terms of the ISO Tariff applicable to the ISO's evaluation of the TTS and WGD projects, even assuming *arguendo* that the TTS and WGD were needed, TTS and WGD would not be permitted to build and own the projects they proposed under the applicable terms of the ISO Tariff because, among other things, only Participating Transmission Owners ("Participating TO" or "PTO") with a PTO Service Territory are permitted to build reliability projects like those proposed by TTS and WGD, and TTS and WGD are not PTOs with a

PTO Service Territory. For these reasons, the Commission should deny the Complaint without further proceedings.

I. Background and Overview.

On December 15, 2008, TTS submitted applications to the ISO for eleven proposed projects through the 2008 Request Window[3] for the 2009 Transmission Plan. TTS "sought approval for the installation, ownership, and operation of Smart Grid devices to perform reliability functions"[4] For each proposed project, TTS requested "a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required for [Pacific Gas and Electric Company ("PG&E")] to complete their long term plan."[5] In other sections of its request window submissions, TTS made it clear that it was "offering PG&E a SVC equipment lease of 5 years to meet system reliability." The request window submissions for reliability projects in the Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E") service territories contain similar provisions. TTS proposed an in-service date of October 15, 2010 and a commercial operation date of November 15, 2010 for its projects.[6] TTS stated in its request window submissions that it intended its facilities to serve as interim solutions until PG&E's long-term solutions are implemented.[7] For example, in its request window submission form for the Kern-Old River local

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3 Capitalized terms not otherwise defined herein have the meanings set forth in the Master Definitions Supplement, Appendix A of the ISO tariff.

4 Attachment A contains excerpts from each of the TTS submission packets.

5 *Id.*

6 *Id.*

7 *Id.*

reliability area, TTS stated that “due to the lengthy approval process and long lead times required to implement [PG&E’s] long-term plan, Transmission Technology Solutions (TTS) is proposing an interim solution.”

The ISO held stakeholder meetings and provided comment periods consistent with the ISO tariff, issued a draft 2009 transmission plan on February 13, 2009, and posted a final 2009 transmission plan on March 20, 2009. One TTS proposal was specifically rejected in both the draft and final 2009 transmission plans because the ISO did not find a need for any interim solution. The March 20, 2009, final 2009 transmission plan listed 33 projects that “required further information or evaluation,” including all ten TTS proposals still under consideration. At a March 24, 2009, transmission planning stakeholder meeting, the ISO provided parties with notice of the ISO’s intention to evaluate these projects in an amended 2009 transmission plan, consistent with a TTS request that its projects be evaluated in the 2009 planning cycle.

The ISO completed its evaluation of the remaining ten project proposals and provided them in an amendment to the final 2009 transmission plan that was posted on June 8, 2009. This amendment reflected the final disposition of the ten remaining TTS projects as well as the PG&E reliability projects that had been evaluated as alternatives. Among other things, the amended 2009 transmission plan explained that the ISO did not have the authority to direct a Participating TO to enter into leases with specific service providers or equipment vendors. The ISO had also explained the limits on its authority under the ISO tariff in communications with TTS representatives and counsel earlier in the spring of 2009.

On November 19, 2009, TTS applied to the ISO to obtain PTO status. On December 3, 2009, the ISO sent TTS a letter stating again that the ISO had not approved any of TTS' proposed projects and explaining why TTS's application to become a Participating TO must be denied under applicable provisions of the Transmission Control Agreement and the ISO tariff.

TTS contacted the Commission's Office of Enforcement asking that they commence an investigation into the ISO's treatment of TTS' projects and Participating TO application. TTS' provided the Office of Enforcement with the documentation supporting its allegations. Likewise, the ISO indicated why its treatment of the TTS projects and its evaluation of TTS' Participating TO application were fully consistent with the ISO tariff. The Commission's Office of Enforcement did not take any action against the ISO.

On November 30, 2009, WGD submitted applications to the ISO for eight proposed projects through the 2009 Request Window for the 2010 Transmission Plan. The ISO evaluated WGD's proposed battery solutions as transmission elements consistent with the Commission's January 21, 2010 order on WGD's petition for declaratory order seeking transmission rate incentives for certain proposed energy storage projects.[8] The ISO held stakeholder meetings and provided comment periods consistent with the ISO tariff, issued a draft 2010 transmission plan in February 2010, following by a supplemental draft

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8 *Western Grid Development, LLC,* 130 FERC ¶ 61,056 at P 97 (2010).

transmission plan (with San Francisco results) in March, and posted a final transmission plan on April 7, 2010. In the final 2010 transmission plan, the ISO rejected seven of the eight proposed battery solutions submitted by WGD and stated that it was still considering a comprehensive solution for the myriad of reliability problems in the area of Placer County, California, including evaluation of a battery storage unit as a possible component of a comprehensive solution in that area. As explained in further detail below, the ISO rejected the proposed battery storage solutions (other than the proposed battery storage solution in the Placer area) in the final 2010 transmission plan because (1) there was no reliability need for any transmission upgrade or addition in three of the areas where WGD submitted projects, and (2) the other project proposals submitted by WGD were not the best cost-effective solution to meet the identified reliability needs, based on the ISO's evaluation of the relative merits of alternative proposals.

Because WGD was not and is not a Participating TO with a PTO Service Territory, it was not eligible to build and own a reliability project under the express terms of the ISO Tariff. However, the ISO evaluated the battery storage solutions to determine whether it should require the applicable PTO with a PTO Service Territory – in this case PG&E to build such projects.

On June 4, 2010, the ISO filed with the Commission a tariff amendment ("RTTP Tariff Filing") to implement a revised transmission planning process ("RTTP").[9] Green Energy Express LLC and 21st Century Transmission Holdings,

9 The ISO submitted the RTTP Tariff Amendment in Docket No. ER10-1401-000.

LLC (together "Green Energy") filed, on July 2, 2010, a petition for declaratory order seeking a ruling on PTO rights to finance, construct, and own various categories of transmission projects under the ISO tariff.[10]

On July 26, 2010, the Commission accepted and suspended the RTTP Tariff Filing to become effective on the earlier of January 3, 2011, or a date set in a further Commission order, and directed Commission staff to convene a technical conference to obtain additional information to evaluate the issues raised in that filing and the Green Energy petition.[11] The technical conference was held on August 24, 2010, and parties submitted two rounds of post-technical conference comments. On December 16, 2010, the Commission issued an order accepting the RTTP Tariff Filing, subject to a compliance filing, with a December 20, 2010, effective date and denying the petition for declaratory order filed by Green Energy.[12]

Complainants allege that the ISO violated the Federal Power Act ("FPA") by engaging in unjust, unreasonable, and discriminatory decisions and actions with respect to their proposed projects. In particular, Complainants argue that the ISO (1) granted an incumbent utility an "undue preference or advantage" in the transmission planning process, in violation of Section 205(b) of the FPA; (2) acted arbitrarily and capriciously in its review and denial of Complainants' proposed projects, in violation of the ISO tariff and the Commission's Order No.

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10 Green Energy filed this petition for declaratory order in Docket No. EL10-76-000.

11 *Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,067 (2010).

12 *Cal. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,224 (2010) ("RTTP Order").

890[13]; (3) elected to resolve certain known reliability violations by choosing not to serve customers (*i.e.*, to "shed load") in violation of the ISO's Planning Standards, rather than by approving the proposed projects; (4) deprived ratepayers of the opportunity of realizing approximately $124 million in total cost savings, as well as certain valuable additional system benefits; and (5) precluded the objective evaluation of projects proposed by non-incumbents, such as Complainants, of proposed "advanced transmission technologies" projects, which are specifically encouraged by federal law and Commission precedent.[14]

Complainants request that the Commission issue an order requiring that the ISO conduct proceedings specifically to evaluate Complainants' proposed projects in comparison with the alternative solutions approved by the ISO through the transmission planning process, based on the original available data.[15] Such a remedy would, of course, serve no purpose because, under unambiguous provisions of the ISO tariff recently affirmed by the Commission, where a reliability upgrade or addition is found to be need, the PTO with a PTO Service Territory in which the upgrade or addition is located shall be the entity responsible for building, financing, owning and maintaining such upgrade or addition. TTS and WGD were not eligible to build reliability-driven projects.

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13 *Preventing Undue Discrimination and Preference in Transmission Service,* Order 890, FERC Stats. & Regs. ¶ 31,241 at P 418-602, *order on reh'g,* Order No. 890-A, FERC Stats & Regs. ¶ 31,261 (2007), *order on reh'g* , Order 890-B, 123 FERC ¶ 61,299, (2008) *order on reh'g,* Order 890-C, 126 FERC ¶ 61,228 (2009).

14 Complaint at 1-2.

15 Complaint at 2.

As discussed in greater detail below, Complainants claims are based on a misunderstanding of the ISO tariff and related documents, conclusory statements, factual inaccuracies, and a deeply flawed cost comparison analysis. The Commission should deny the Complaint without further proceedings because it lacks any legal or factual basis.

II. Answer.

A. Only PTOs With a PTO Service Territory Are Authorized to Build Reliability Projects Under the ISO Tariff.

The fundamental basis for the Complaint is the claim that Complainants should have the ability to construct the projects that they proposed in the ISO's 2008-2009 and 2009-2010 transmission planning cycles and that the ISO should have approved those project proposals under then-applicable provisions of the ISO tariff. The projects that both TTS and WGD proposed to build were reliability-driven projects. At the outset, it is important to note that, under the unambiguous language of the Commission-approved ISO tariff, TTS and WGD were not – and are not – eligible to build reliability-driven projects. As Complainants acknowledge, section 24.1.2 of the ISO tariff in effect during the periods covered by the Complaint provides that, in the case of reliability projects such as TTS' proposals, where the ISO finds a reliability project to be needed, the PTO with a PTO Service Territory in which the project will be located "shall be the Project Sponsor, with responsibility to own, construct, finance, and maintain the project." [16] This tariff requirement is unambiguous, and the Commission explicitly affirmed in the RTTP Order that PTOs with PTO Service

16 Complaint at 19, citing section 24.1.2 of the ISO Tariff.

Territories have the right to build reliability projects under tariff provisions substantively identical to section 24.1.2.[17]

The Commission's recognition of the construction rights of PTOs is fully supported by the language of the ISO tariff. Indeed, PTOs have been designated as the sole builders of reliability projects under the ISO tariff since the ISO commenced operations in the 1990s.[18] Complainants note that under section 24.1.2, the ISO is required to evaluate "all potential projects submitted to address then-known reliability violations."[19] Some parties have noted in other proceedings that because section 24.1.2 also states that any market participant, and certain other entities, may *propose* a reliability-driven project and have argued that this implies that market participants other than PTOs can build and own reliability-driven projects.[20] Such a tariff interpretation is patently contrary to the plain and explicit language of the ISO tariff. Nothing in the provision identifying entities that can propose reliability-driven projects refers to, or even implies, construction or ownership rights. Indeed, the provision that restricts

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17 RTTP Order at PP 59, 62.

18 *See* Section 3.2 of the ISO tariff filed with the Commission in 1997 and accepted by the Commission in *Pacific Gas and Elec. Co., et al.*, 80 FERC ¶ 61,128, at 61,433-35 (1997).

19 Complaint at 5 (emphasis in original).

20 The ISO modified Section 24.1.2 (now Section 24.4.6.2) as part of an October 31, 2008 compliance filing in which the ISO responded to the Commission's request for clarification as to how Participating TO reliability projects were to be evaluated. The ISO proposed to require all reliability-driven transmission project proposals, including those submitted by PTOs as well as other interested parties, to be submitted through the request window for greater transparency and comparability. This provision simply recognizes that the ISO conducts an open stakeholder process under Order No. 890, that allows all stakeholders to propose transmission (or other) solutions or suggest alternatives to meet identified needs. The ISO did not, however, modify the long-standing explicit tariff language regarding the obligation of the Participating TO with a PTO Service Territory to finance, own and build reliability projects. See October 31, 2008, transmittal letter in Docket No. OA08-62-002 at pp. 18, 114; ; *see also California Independent System Operator Corp.,* 127 FERC ¶ 61,172 at P 65 (2009). .

such rights to PTOs immediately follows the provision discussing who can propose of proposals. Moreover, under such an interpretation, the section would authorize entities such as the California Public Utility Commission and the California Energy Commission to build and own projects. It is a basic canon of contractual and tariff construction that interpretations that yield absurd results are to be rejected.[21] The Commission has recently rejected similar arguments concerning the entities that can build location-constrained resource interconnection ("LCRI") facilities. Green Energy and others argued that because the ISO tariff allows any interested party to propose transmission additions as LCRI projects, it would be unreasonable to infer that market participants will propose such facilities if this provision does not also imply a right to build such facilities.[22] The Commission rejected this argument and found that the existing ISO tariff provides only Participating TOs with existing network transmission facilities the ability to construct LCRI facilities and that non-PTO transmission developers are not eligible to build these facilities.[23]

B. General Arguments Regarding the TTS Projects.

1. The ISO Properly Rejected TTS' Application for PTO Status.

Complainants contend that the ISO's denial of TTS's application to become a PTO "has been a major obstacle to TTS in its overall effort to obtain

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21 *See, e.g.*, *United States v. Irvine,* 756 F.2d 708, 710-11 (9th Cir. 1985).

22 *See* RTPP Order at P 123.

23 *Id.* at P 134.

approval of its projects."[24] The ISO assumes for the purpose of this discussion that Complainants, by "approval," refer to approving construction and ownership of the projects by TTS, rather than approval of those projects to be constructed by an existing PTO.[25] Their arguments in this regard are, variously, incorrect, irrelevant, or both.

Complainants first point out that, under section 4.3.1.1 of the ISO tariff, the ISO may receive applications to become a PTO and that the application must identify the facilities that the applicant intends to place under the ISO's operational control.[26] All of this is accurate, but the ISO did not violate that section. The ISO received the TTS application as described in the tariff. Subsequently, the ISO rejected that application because the ISO had rejected TTS' proposed projects and was no longer considering them in the transmission planning process; the facilities identified by TTS were not in existence (or approved in the transmission planning process); and TTS had no facilities to turn over to the ISO's Operational Control.[27] Moreover, as noted above, even if one assumes *arguendo* that the ISO had approved TTS' proposed projects, under Section 24.1.2 of the ISO tariff, the applicable Participating TO with a PTO Service Territory would have been responsible for building and owning such

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24 Complaint at 17.

25 The ISO rejection of the project proposals themselves, regardless of who would construct them, is discussed below.

26 Complaint at 17.

27 *See* Attachment E to Complaint.

facilities. That the ISO may receive an application does not compel the ISO to approve it.

Complainants next assert that neither the tariff for the Transmission Control Agreement requires that a PTO applicant have a service territory to qualify as a PTO.[28] This is also correct, but the ISO did not reject the TTS PTO application on the basis that a PTO applicant must have a PTO Service Territory. Rather, the ISO rejected it for the reasons specified above.[29] TTS was proposing to build reliability-driven projects to be included in the transmission plan. Although neither the ISO tariff nor the Transmission Control Agreement requires that the PTO have a PTO Service Territory, the ISO tariff *does* provide, as noted above, that only PTOs *with a PTO Service Territory* can be assigned to build a reliability driven projects identified in the transmission plan.[30] TTS does not have a service territory, so it was not eligible to build the project it was proposing. Because TTS had neither existing transmission facilities nor a project that could be approved as a TTS-owned project in the ISO transmission plan, TTS could not qualify as a PTO.

Complainants further argue that none of the criteria that the ISO is to consider regarding PTO status, as set forth in section 2.2.3 of the Transmission Control Agreement, requires that that the facilities be constructed or included in

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28 Complaint at 17-18,

29 *See* Attachment E to Complaint.

30 A PTO Service Territory is defined in relevant part in Appendix A to the ISO tariff as "The area in which an IOU [investor-owned utility], a Local Public Owned Electric Utility, or federal power marketing authority that has turned over its transmission facilities and/or Entitlements to CAISO Operational Control is obligated to provide electric service to Load."

the transmission plan.[31] Complainants neglect the fact that section 2.2.3.v requires that the applicant be capable of performing its obligations under the Transmission Control Agreement. An entity cannot perform those obligations unless it has operational facilities. Because the ISO did not approve TTS' proposals, TTS had no operational or approved facilities that could be turned over to the ISO's operational control.

Complainant's argument also ignores other provisions of the Transmission Control Agreement and ISO tariff. Under sections 4.1 of the Transmission Control Agreement, one obligation of a PTO is that it turn over to the ISO's operational control "transmission lines and associated facilities forming part of the transmission network that it owns or to which it has Entitlements." "Participating TO" is defined in Appendix A of the ISO Tariff as "[a] party to the Transmission Control Agreement whose application under Section 2.2 of the Transmission Control Agreement has been accepted and who has placed it transmission assets and Entitlements under the [ISO's] Operational Control in accordance with the Transmission Control Agreement." The definition speaks in terms of completed, not potential, acts. In addition, Section 2.2.5 of the Transmission Control Agreement provides, "A Party whose application under this Section 2.2 has been accepted shall become a Participating [Transmission Owner] *with effect from the date when its TO Tariff takes effect*." (Emphasis

31 Id.

added.) As a general matter, the TO Tariff will only take effect when the transmission line is energized and operated by the ISO.[32]

This Commission has confirmed this interpretation of the ISO Tariff in the RTPP Order in the context of the rights of PTOs to construct Network Upgrades identified Large Generator Interconnection Process ("LGIP"):

> We further find that the term "PTO" refers to PTOs with existing network transmission facilities. Thus, a transmission developer would be precluded from building LGIP network upgrades until it has already met the tariff definition of PTO and fulfilled the requirements of the Transmission Control Agreement as discussed earlier. The language in the definition of a PTO indicates that, to be a PTO, facilities must already have been turned over to CAISO. Section 2.2.5 of the Transmission Control Agreement supports this interpretation.[33] Therefore, we conclude that currently only a PTO with existing network transmission facilities has the obligation to build LGIP network upgrades.[34]

In some cases, in order to facilitate regulatory approvals, financing, or construction for projects that have already been approved in the ISO's transmission planning process, or for a change in ownership for facilities that are already part of the ISO Controlled Grid, the ISO will grant conditional approval of

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32 *See Trans Bay Cable*, 129 FERC ¶ 61,225 (2009) at Ordering Paragraph (A); *Trans-Elect NTD Path 14, LLC*, 109 FERC ¶ 61,249 (2004) at Ordering Paragraph (A), *reh'g denied* 111 FERC ¶ 61,140 (2005). An exception might occur if the Commission were to grant CWIP recovery to an entity that is building a project approved under the transmission plan but is not yet a PTO. Neither the ISO tariff nor the Transmission Control Agreement addresses this circumstance.

33 The LGIP incorporates the CAISO tariff Appendix A definitions, which define a "Participating TO" as "[a] party to the Transmission Control Agreement whose application under section 2.2 of the Transmission Control Agreement *has been accepted* and who *has placed* its transmission assets and Entitlements under Operational Control in accordance with the Transmission Control Agreement." CAISO Tariff, Appendix A (emphasis added). CAISO Transmission Control Agreement, § 2.2.5 ("A Party whose application under this Section 202 has been accepted shall become a Participating TO *with effect from the date when its TO Tariff takes effect.*") (emphasis added).

(Footnote from original.)

34 RTPP Order P 95 and n. 101.

a PTO application.[35] However, actual PTO status only becomes effective when the completed line is placed under ISO operational control (and, as noted above, when the TO Tariff becomes effective). The ISO reserves such conditional approvals for projects that already exist or have been approved in the transmission planning process. To do otherwise would be highly inefficient. It would expose the ISO to the possibility of multiple applications for PTO status, multiple amendments of the Transmission Control Agreement, and multiple regulatory proceedings, all concerning projects that might never be constructed. Restricting conditional approval in connection with to projects that do not yet exist to those that have gone through the transmission planning process both provides a greater certainty that the projects will be built and also encourages participation in the transmission planning process. To do otherwise, would allow any entity to apply to become a Participating TO even though it has no existing transmission facilities, no transmission facilities approved in an ISO transmission plan, and no transmission project proposals even pending consideration. The Transmission Control Agreement is not a means for pre-certifying entities that may desire to become a Participating TO at some unspecified future date. That would be a frivolous exercise which would unnecessarily expend ISO resources and serve no valid current purpose.

Perhaps recognizing the lack of tariff and Transmission Control Agreement support for their arguments, Complainants seek to buttress their claims by citing Commission policy. Their citations, however, have little to do

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35 *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 117 FERC ¶61,029 at P 5 (2006).

with the ISO's denial of PTO status for TTS. They point out that the Commission, in Order No. 890, encouraged, but did not require, the use of open seasons for upgrades identified in transmission plans.[36] The Commission's statements in this regard, however, did not concern proposals by independent developers to construct projects. Rather, the Commission was encouraging transmission providers to provide *customers* the opportunity to participate in projects through *joint ownership*.[37]

Complaints also cite the Commission's statement, in its order on the ISO's Order No. 890 compliance filing:

> Customers and stakeholders must not be excluded from the development of PTO-sponsored projects and PTO plans should not be incorporated into the [ISO] plan using criteria and standards that are different from those used to assess alternative projects.[38]

Contrary to Complainants' implication, the Commission was not speaking to the ability of independent developers to build reliability projects and thus become PTOs. It was speaking to participation of stakeholders in the development of *PTO-sponsored projects* and the criteria by which the ISO evaluated those projects.[39] In that same order the Commission found that, with minor adjustments, the ISO's transmission planning process, *which retained long-standing tariff provisions reserving reliability projects for PTOs with PTO Service Territories*, was consistent with Order No. 890.

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36 Complaint at 18, citing Order No. 890 at P 594.

37 Order No. 890 at P. 594.

38 Complaint at 18, *citing Cal. Indep. Sys. Operator Corp.*, 123 FERC ¶ 61,283 at P 16 (2008).

39 *Id.* at PP 15-17.

From these irrelevancies, Complainants segue into their contention that the ISO's "interpretation" of the ISO tariff and the Transmission Control Agreement constitute a "Catch 22," so that TTS could not become a PTO, and thereby the owner of a reliability-driven project.[40] As explained above, Complainants premise is fundamentally flawed. The problem with their logic is that TTS could not own a reliability project that it proposed *even if it were a PTO.* PTO status would not provide TTS a PTO Service Territory and it would thus remain ineligible to construct reliability projects (except as a contractor of a qualified PTO). As the ISO indicated to TTS, merely being a Participating TO does not entitle an entity to build and own a reliability project; building an owning reliability projects is limited to Participating TOs with a PTO Service Territory.

Complainants also err by asserting that the ISO's "interpretation" of the ISO tariff and the Transmission Control Agreement would make it impossible for an independent developer ever to become a PTO.[41] The error is both factual and legal. First, the ISO already has three existing PTOs that are independent developers: Trans-Elect, Trans Bay Cable, and Startrans. Second, there are other avenues under the tariff and Transmission Control Agreement by which an independent developer can become a PTO. The developer can obtain approval through the transmission planning process of an economically driven project (or, under the current tariff, a policy-driven project), including conditional approval while the project is being constructed. The developer could also independently

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40 Complaint at 18. Complainants later repeat, "unless TTS was already a PTO, TTS could never own a reliability project that it proposed." *Id.* at 19.

41 Complaint at 19.

obtain regulatory approvals to build the project and apply for PTO status after the project is completed. What the developer cannot do is obtain PTO status by proposing a reliability project in the transmission planning process.

Complainants conclude their argument about the ISO's denial of TTS's application for PTO status by asserting that the assignment of reliability-driven projects to PTOs with PTO Service Territories is discriminatory and an impediment to many types of Smart Grid reliability innovations.[42] The ISO has explained at length in other proceedings why PTOs with PTO Service Territories are differently situated from other market participants and why the differential treatment of such PTO in this regard is justified, but it need not repeat those arguments here because, again, the Commission has rejected the arguments that Complainants raise. In the RTPP Order, the Commission declined to instigate a proceeding under section 206 of the FPA to consider whether the existing right of PTOs to with PTO Service Territories remains just and reasonable and not unduly discriminatory.[43] The Commission found that the parties in that proceeding requesting Commission action under section 206 had failed to provide sufficient factual evidence or legal justification to change the existing reliability project provisions. The Complaint is similarly lacking.

Complainants' argument that denying TTS' application for Participating TO status will impede innovation and smart grid development is likewise misplaced. The purpose of the ISO's assessment of reliability projects is to identify the

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42 *Id.*

43 RTPP Order at 62.

transmission upgrades or additions (or non-transmission alternatives) that best meet the ISO's identified reliability needs in a cost-effective manner. That upgrade or addition can be a project proposed by the PTO, an alternative proposed by some other stakeholder, or a solution identified by the ISO. The ISO tariff does not require the ISO to approve the project proposed by the Participating TO if it is not the best solution. Thus, under the ISO tariff, ratepayers are not required to pay for PTO-proposed projects that are not the best solution to an identified need from a technical standpoint or otherwise. The ISO evaluates all feasible alternatives to determine what the best solution to meet the reliability need is, and the Participating TO is obligated to build that solution. In other words, if the ISO approves a smart grid innovation, the Participating TO must build it. If a developer of new technologies proposes a technology-based solution in the ISO planning process, and if the ISO directs a Participating TO to build such a solution, there is every reason to believe that the PTO would be interested in entering into voluntary arrangements with any developers/proponents of such technologies that are truly competitive. Thus, the tariff does not serve as an impediment to smart grid projects – provided they are a cost-effective means of meeting the identified reliability need.

The ISO also notes that Static Var Compensator ("SVC") and battery storage technologies are not brand new concepts. Indeed, the ISO's Participating TOs already have SVC equipment at several locations on their systems. Similarly, the ISO has an ongoing pilot program with a battery storage unit, and the Participating TOs and other entities in California are in the process of developing storage projects.

2. The ISO Lacks the Authority to Require PTOs to Negotiate Contracts with Specific Parties.

Complainants explain that TTS requested that the ISO direct Pacific Gas and Electric Company ("PG&E") to enter into good faith negotiations to develop renewable 5-year service contracts (*i.e.,* leases) with respect to the TTS projects.[44] Complainants contend that because the ISO, in the Amended 2009 Transmission Plan, described the TTS projects as interim solutions to reliability concerns in PG&E's service territory, the ISO should have approved TTS's proposal. Presumably, consistent with the TTS proposal, Complainants contend that the ISO should have required PG&E to enter into the proposed service contracts.

As explained below, although the ISO stated in the Amended 2009 Transmission Plan that the TTS project would address a short term reliability need, it did not approve the TTS projects, as proposed by TTS. In addition, the ISO explained in the amended plan that it did not have the authority under the ISO tariff to direct PG&E to contract with TTS to provide the services.[45] Complainants do not explicitly challenge this statement, but their argument assumes without explanation or support that the ISO has such authority.

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44 Complaint at 6.

45 Attachment D, amendment to the 2009 Transmission Plan, at 297

To the contrary, the ISO's authority to direct its PTOs is limited to specific circumstances. The ISO's relationship with the PTOs is governed by the Transmission Control Agreement and the ISO tariff.

Section 4.3 of the Transmission Control Agreement specifically provides that rights and responsibilities that have not been transferred to the ISO as operating obligations under section 4.1.1 of the agreement remain with the PTO. Section 4.1.1 states that, with certain exceptions not relevant here, each PTO shall place under the ISO's Operational Control the transmission lines and associated facilities forming part of the transmission network that it owns or to which it has Entitlements. Section 5.1.2 describes the nature of operational control. That control is exercised for the purposes of (1) providing a framework for the efficient transmission of electricity across the ISO Controlled Grid in accordance with the ISO tariff; (2) securing compliance with all Applicable Reliability Criteria; (3) scheduling transactions for Market Participants to provide open and non-discriminatory access to the ISO Controlled Grid in accordance with the ISO tariff; (4) relieving Congestion; and assisting Market Participants to comply with other operating criteria, contractual obligations and legal requirements binding on them. None of these authorities provide the ISO with any ability to instruct PTOs to enter into specific contracts with specific vendors for equipment.

The ISO tariff does provide certain other authorities, including the authority to direct PTOs to construct certain transmission facilities included in the ISO transmission plan, but it does not at any point suggest that the ISO has the authority under the planning provisions of the ISO tariff to direct a PTO to contract with a specific vendor or sub-contractor to construct transmission facilities included in an ISO transmission plan.

As noted, the ISO's relationship with its PTOs is governed by the Transmission Control Agreement and the ISO tariff. Inasmuch as neither document provides the ISO with the authority that Complainants presume, that authority does not exist.

As Complainant's note, issues related to the ISO's treatment of TTS project proposals were discussed with Commission Office of Enforcement staff in response to a call by TTS to the enforcement hotline, as well as the submission of documentation to support their claims.[46] The ISO explained these limitations on the ISO's authority to require a PTO to enter into vendor or services contractor leases to enforcement staff, and enforcement staff did not suggest that the ISO had the authority presumed by Complainants

C. The ISO's Consideration of the TTS Projects Was Consistent with the ISO Tariff.

1. The Background Information Concerning the TTS Projects in the Complaint Is Incomplete and Does Not Reflect Relevant Communications with the ISO.

The affidavit of Ms. Jenny Mueller contains factual assertions about the TTS interim solution proposals and TTS' understanding of the process followed by the ISO to assess these request window submissions. She states generally that the ISO improperly rejected the TTS (and WGD) projects "without substantial

46 Complaint at 31.

evidence" and based on "erroneous" facts.[47] The affidavit of Ziad Alaywan contains a factual discussion about the ISO's cost comparison between the TTS interim proposals and PG&E's long term proposals. He generally concludes that "at least two" of the TTS projects were more cost-effective than the PG&E long-term solutions approved by the ISO in the transmission plan.[48] In the following sections, the ISO responds to the various factual allegations in the Complaint and supporting documents.

The Mueller affidavit sets forth details about meetings between TTS and ISO, and TTS and PG&E, personnel.[49] The descriptions of the TTS-ISO meetings are inaccurate and incomplete.[50] For example, contrary to Ms. Mueller's claim, the June 19, 2008 and December 15, 2008 meetings between the ISO and TTS did not include ISO legal representatives, and TTS does not even attempt to identify the ISO legal representatives that were purportedly at this meeting.[51] Since the December 15, 2008 meeting was not attended by ISO legal representatives, that meeting did not "educate" the ISO's legal team about how the ISO "had the legal grounds to accept the TTS projects." Both the June 19, 2008 and December 15, 2008 meetings were limited to a technical discussion

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47 Mueller affidavit, ¶¶.9-10.

48 See Alaywan affidavit, ¶ 9. These alleged cost savings are based on a flawed and generally inapplicable to the capital cost evaluation process addressed in detail in the Declaration of Neil Millar.

49 Mueller affidavit, ¶¶11-15, 21.

50 The ISO has no basis upon which to respond to the statements regarding meetings between PG&E and TTS.

51 Deshazo Declaration at ¶¶ 5-7.

of the TTS SVC equipment between ISO and TTS engineers and technical representatives.[52]

Interestingly, the Mueller affidavit fails to mention the legal meetings and discussions that did take place between the attorneys for TTS and the ISO. The affidavit of Andrew Ulmer, in house counsel for the ISO, describes these meetings and the discussions between the TTS and ISO attorneys. As described by Mr. Ulmer, the ISO legal team was contacted by local counsel for TTS in early March, 2009.[53] When asked about the status of the TTS projects and whether the ISO intended to "approve" them, ISO counsel referred TTS counsel to tariff Section 24.1.2 which provides that only PTOs with a PTO Service Territory are permitted to build and own reliability projects under the ISO Tariff.[54] At a March 12, 2009, meeting attended in person by TTS local counsel and on the telephone by representatives from Andrews Kurth, ISO counsel again explained the ISO's transmission planning process and the impact of Section 24.1.2 on the ISO approval of reliability projects.[55]

Following the March 12, 2009, meeting, Mr. Ulmer called TTS' local counsel, Jane Luckhardt, and advised her that the ISO did not have the tariff authority to direct Participating TOs to enter into 5 year leases for SVC equipment with specific vendors (consistent with the discussion at the meeting). This telephone conversation took place on April 24, 2009. At the same time, Mr.

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52 *Id.*

53 Ulmer Declaration at ¶2

54 *Id.*

55 *Id.* at ¶¶3-4

Ulmer told TTS counsel that the ISO intended to amend the 2009 Transmission Plan to reflect this legal conclusion and further describe the ISO's evaluation of the TTS proposals.[56] ISO counsel also discussed Section 24.1.2 with TTS technical personnel on July 23, 2009 [57]

It is clear from the Ulmer affidavit that TTS was aware of the ISO's legal position by no later than April 2009 and should have understood that the ISO was not going to "approve" a lease between TTS and PG&E, which is what TTS requested in its request window submission packet.[58] Thus, Ms. Mueller's assertion that there was only an "indication" that the ISO did not accept the proposals in May 2009, when the Study Plan was issued, and no definitive statement until December 2009[59] is misleading and incorrect. The fact that the ISO referred to the projects as potential short-term mitigation solutions in the amended Transmission Plan issued in June 2009[60] does not in any way alter the fundamental premise that the ISO informed TTS in Spring of 2009 that the ISO did not have the authority to approve the specific TTS proposals for five year lease arrangements with the Participating TOs as proposed by TTS. Indeed, consistent with the telephone conversation between Ms. Luckhardt and Mr.

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56 *Id.* at ¶ 5

57 Deshazo Declaration at ¶ 8.

58 As discussed below, TTS appeared to seek several different approaches to cost recovery for the SVC equipment and its position on this issue is confusing, at best.

59 Mueller Affidavit at ¶¶ 19 and 37.

60 Mueller affidavit at ¶ 20.

Ulmer, the ISO set forth its legal position with respect to Section 24.1.2 in the June 2009 amended plan.[61]

The ISO's 2009 Transmission Plan identifies TTS' proposed projects in the summary of request window submissions at page 10.[62] The TTS projects were also listed in Table 1-4 under Section 1.2.5 of the Plan, entitled *Ongoing Projects Not Eligible For Approval Recommendation in the 2009 Transmission Plan.* That table identified the TTS projects as "interim solutions" that were under evaluation in the 2009 study cycle (*see* pages 18-20 of the Plan).[63]

In June 2009, the ISO completed its evaluation of the TTS interim proposals as well as four PG&E long-term solutions. At page 297 of the amended 2009 transmission plan, the ISO stated that it had completed its analysis of PG&E's proposed long-term solutions and determined that they could move forward to implementation. The ISO said nothing of the like regarding the proposed TTS solutions. With respect to TTS' proposal that the ISO require PTOs to enter into good faith negotiations to lease the SVC equipment from TTS, the ISO stated that it did not have the authority under its tariff to so direct a PTO.

Under Section 24.1.2 of the ISO Tariff, the PTO in whose Service Territory the upgrades or additions will reside must be the project sponsor responsible for constructing, owning and financing any reliability upgrade or addition. Thus, if the ISO had approved and required installation of the SVC facilities proposed by TTS, the ISO would have been required to direct PG&E to own and install such

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61 See Attachment D amendment to the 2009 Transmission Plan, at 297.

62 See Attachment C.

63 *Id.*

SVC facilities. However, the final 2009 Transmission Plan did not include such a requirement. This is further evidence that the ISO did not approve the SVC facilities proposed by TTS. The ISO's consideration of the TTS proposals concluded in June 2009. At page 294 of the amended plan, the ISO stated that there "will be no additional amendments to the plan." Thus, the ISO did not approve TTS proposals, and those proposals are no longer pending consideration in the planning process.

In light of the ISO's consistent message in conversations with representatives of TTS and the clear statement in the amended 2009 transmission plan that the ISO did not have the authority to direct the PTOs to lease SVC equipment from TTS, it seems disingenuous for Ms. Mueller to state, repeatedly throughout her affidavit, that on December 3, 2009, that she learned from the ISO "for the first time" that the ISO had "formally rejected all the TTS projects."[64]

2. The ISO's Evaluation of the TTS Proposals was Transparent, Non-Discriminatory and in Compliance with Tariff and BPM Requirements.

a. Throughout the Development of the Draft, Final, and Amended Versions of the 2009 Transmission Plan, the ISO Provided Information and Opportunities for Comment on the Disposition of the TTS Proposals.

In accordance with the then applicable provisions of the ISO's transmission planning business practice manual ("BPM") Section 2.1.1.2, the ISO

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64 *See* Mueller affidavit at ¶¶ 23, 37, 42, 47, 52, 56, 60 and 65. In contrast, Ms. Mueller does acknowledge, the ISO's specific reference to Section 24.1.2 as being dispositive of the question of the ISO's authority to order a participating TO with a service territory to enter into a five year lease. See Mueller affidavit, par. 33.

(as a Planning Authority) and the Participating TOs with service territories (as Transmission Planners) conduct planning studies of their respective systems in accordance with the NERC reliability planning standards TPL-001 through TPL-004. The BPM describes the coordination that takes place between the ISO and Participating TOs while the study assumptions and base cases are developed. The BPM makes it clear that the Participating TOs submit, within thirty days after the ISO has posted its technical study results, both their own study results and also projects responding to the ISO's needs analysis.[65] The tariff and BPM are equally clear that only transmission upgrades and additions – capital projects – must be submitted through the request window, along with demand response or generation alternatives. The Participating TOs are not required to submit operating procedures, special protection schemes, load/generation shedding or default isolation, or other mitigation solutions through the request window.[66]

Both the draft and final versions of the 2009 Transmission Plan explained that the ISO complied with its planning responsibilities under the NERC planning standards by studying the near term (one to five year) and long term (five to ten year) planning horizons. For the 2009 planning cycle, 2013 was studied as the near-term horizon and 2018 was studied as the long term horizon (except for

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65 BPM Ver. 4.0, Section 2.1.1.2. Modifications were later made to that paragraph after the 2009 Transmission Plan had been amended.

66 Former tariff section 24.2.3; current tariff 24.4.3; BPM Ver. 4.0, Section 3.

TPL-004, which was studied only for the near term).[67] The Participating TOs studied the interim years as well as 2013 and 2018.[68]

Although the Participating TOs were required to submit capital projects through the request window corresponding to the needs identified by the ISO in the reliability studies Reliability Assessment, there was no obligation to provide short-term mitigation solutions through the request window for these studies that were not capital equipment additions or upgrades. Consistent with the timeline established in the ISO tariff and BPM, the Participating TOs submitted their proposed reliability solutions to the identified reliability needs on October 15, 2008. TTS filed its proposed interim leasing solutions to reliability concerns identified by the ISO in the Reliability Assessment on December 15, 2008 – the day when the request window closed. [69] Thus, there was a compressed period of time for ISO staff to evaluate the submitted projects and alternatives before the draft 2009 Transmission Plan was released on February 13, 2009.[70] Contrary to Ms. Mueller's statement,[71] the draft 2009 Transmission Plan addressed only the

67 *See* Attachment E, excerpts from the Amended 2009 Transmission Plan at pages 270-71; *see also id*. at 44.

68 *Id.*, at 271.

69 See Attachment A. The proposals responded to reliability concerns identified in PG&E, SDG&E and SCE service territories; specifically for PG&E the request window submission packets identified studies conducted in 2007 and 2008.

70 See Didsayabutra Declaration at ¶ 7. Note that the draft 2009 Transmission Plan was posted on February 13, 2009 and not on February 27, 2009, as set forth in the Mueller affidavit. February 27, 2009, was the date of the stakeholder meeting to address the draft plan.

71 Mueller affidavit at ¶ 17.

Cottonwood Interim Solution, and that proposal was specifically denied because the ISO did not find a need for any interim solution.[72]

The 2009 Transmission Plan, containing additional information based in part on comments received from stakeholders, was posted on March 20, 2009 prior to the March 27, 2009 Board meeting. That plan, at Table 1-3 (pages 18-20), listed 33 projects that "required further information or evaluation." Table 1-3 identified all ten TTS proposals still under consideration; the status of the Cottonwood Interim Solution remained unchanged.[73] In addition, Table 1-3 contained reliability solutions proposed by PG&E that the ISO intended to evaluate in comparison with the TTS proposals. The status of all the projects listed in Table 1-3 indicated that the projects would be evaluated in the 2009 study cycle.

Appendix C to the final plan contains a matrix of stakeholder comments, including those submitted by Ms. Mueller on behalf of TTS.[74] In her comments, Ms. Mueller questioned why projects under $50 million (such as the TTS proposals) that do not require Board approval could not be approved prior to the issuance of the 2010 Transmission Plan.[75] She also wanted to verify that the TTS proposals were studied as interim solutions and she questioned whether PG&E had submitted a detailed cost breakdown for its proposals.[76]

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72 See Attachment F, draft 2009 Transmission Plan, at 201.

73 Attachment C, final 2009 Transmission Plan (not amended) Table 1-3, pages 18-20.

74 Attachment H, at 283.

75 Attachment I, TTS comments.

76 *Id.*

Prior to the March 26 Board meeting, on March 24, 2009, the ISO also held the first stakeholder meeting of the 2010 transmission planning process to address the draft study plan and unified planning assumptions for that cycle. At that meeting, the ISO explained that the some of the projects listed on Table 1-4 were still under consideration and evaluation as part of the 2009 cycle and that the 2009 transmission plan would be amended to reflect the final disposition of those projects.[77] This approach was consistent with the TTS request to evaluate its projects prior to the 2010 transmission planning cycle.

The final 2009 Transmission Plan was presented to the Board on March 27, 2009 by Gary Deshazo. In the memorandum describing the plan, as well as the slides presented, Mr. Deshazo advised the Board that 33 projects were still under consideration as part of the 2009 cycle.[78] Included in those 33 projects were the PG&E long-term solutions that had been proposed for the reliability concerns in the same areas for which the TTS solutions had been proposed. The evaluation process for some of the Table 1-4 projects concluded with an amendment to the final 2009 Transmission Plan that was posted on June 8, 2009. In the market notice advising stakeholders that the amended plan had been posted, the ISO described the notification given to stakeholders at the

77 See Deshazo Declaration at ¶ 10. On April 7, 2009, PG&E specifically commented on the three reliability projects that were still under consideration in the 2009 Transmission Plan and requested that the ISO move forward as quickly as possible so that these projects could be implemented. See PG&E comments at Attachment J. TTS did not file comments following the March 24, 2009 stakeholder meeting.

78 See Deshazo Declaration at ¶ 9; March 18, 2009 Board Memorandum from Laura Manz, Vice President of Market and Infrastructure Development, at Attachment K.

March 24, 2009, meeting.[79] The amendment to the 2009 Transmission Plan, set forth at pages 298-303, contained the final disposition of the ten remaining TTS projects as well as the PG&E reliability projects that had been evaluated as alternatives. The amendment also described the disposition of three other projects from Table 1-4: PG&E's Wilson Oro Loma 115 kV Reconductor Project; SCE's Alberhill 500kV project, and the SDG&E Bayfront Transmission Substation. The rest of the projects on Table 1-4 were carried over to the 2010 planning cycle. The disposition of each TTS proposal will be discussed in detail in the sections that follow.

As a general matter, the amendment to the 2009 transmission plan very clearly stated in the introductory paragraph to the TTS discussion that the ISO did not have the legal authority, pursuant to its tariff, to require the Participating TOs to enter into equipment lease negotiations with specific vendors. Having repeatedly been advised that the ISO could not accommodate the TTS proposals, it should have been no surprise to TTS that the proposed leases were not included in the final 2010 study plan posted in May, 2009.[80]

Indeed, it is quite surprising for TTS to now argue that "the CAISO did not provide TTS with a meaningful opportunity to be heard concerning the Amended 2009 Transmission Plan." The ISO advised TTS, along with the other stakeholders, on March 24, 2009 that the plan would be amended to reflect the final disposition of the projects that required further evaluation, and the ISO

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79 See Attachment L.

80 See Mueller affidavit at ¶19.

solicited comments at that time. PG&E was clearly concerned about the status of its proposed projects and submitted comments to that effect; in contrast, TTS did not respond. It is also ironic that TTS is now suggesting that the ISO violated its BPM and tariff by *not* evaluating the TTS proposals in the 2010 planning cycle, even though TTS, through Ms. Mueller's comments, requested that the projects be evaluated in the 2009 cycle.[81]

Finally, in both the Complaint[82] and at attachment D to the Mueller and Alaywan affidavits, TTS asserts that the ISO does not provide for transmission plan amendments and that changing the final transmission plan after Board presentation violated tariff Section 24.2.4.1.[83] TTS also argues that a draft of the amendment should have been circulated for comment prior to final posting.

Nothing in this tariff provision suggests that the Board's disposition of the plan cannot be conditioned upon further analysis or action by ISO staff and management. As indicated above, at the Board meeting where the Transmission Plan was presented to the Board, ISO staff expressly advised the Board that other projects were still being considered in the 2009 planning cycle and would be resolved in that planning cycle, including the PG&E long-term solutions and the TTS proposals that were ultimately rejected. Section 24.2.4(d) of the tariff states that projects with capital costs of less than $50 million that do not require

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81 The ISO does not understand the unsupported statement in the complaint that "TTS was improperly barred from project reconsideration in the next CAISO TPP cycle, in violation of its tariff." The tariff has no provision for "reconsideration" and participants are not barred from submitting projects repeatedly, although the outcome of repeated submissions should be fairly obvious.

82 Complaint at 13-14.

83 This section was substantially modified as part of the revised transmission planning process.

Board approval will be identified in the plan but will be approved in accordance with procedures in the BPM. BPM Section 2.2.1 provides that the transmission plan may include information about projects that "require additional study and that can be advanced to mitigate reliability issues." Accordingly, both the tariff and the BPM contemplated that projects with capital costs of under $50 million that require additional study could be advanced and approved after the transmission plan has been finalized.

This procedure is entirely consistent with the steps taken by the ISO.[84] These approvals can take place at any time of the year depending on when evaluation of specific projects is concluded. Because the projects at issue here were all less than $50 million, it was ISO management's obligation under the tariff to approve or disapprove them. While Board approvals of transmission projects occur at a public Board meeting, there is no public meeting process for ISO management. Under the applicable terms of the tariff and the BPM, ISO management could have simply rejected TTS' remaining projects without an additional formal publication. However, in order to be transparent and to find a means for advising stakeholders of management's decisions regarding the TTS projects, the ISO thought the best means for doing that would be to reflect the decisions in an amended Transmission Plan. In that way stakeholders could find

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84 The complaint also contains a discussion about BPM section 2.2.2 that specifically provides for amendments to the transmission plan. That section was added to the BPM, through the ISO's BPM change management process, after the 2009 plan was amended. Nevertheless, the arguments advanced at complaint page 13 and 14 regarding the ISO's failure to comply with that section have no merit and should be disregarded. As described in section 2.2.2, the amendment to the plan quite clearly described status of projects listed as "pending" in the final plan. The status of 13 projects was described, and the rest went on to be evaluated in the 2010 cycle.

all transmission planning decisions pertaining to TTS projects the 2009 transmission planning cycle in one location. The ISO's approach also accommodated TTS' express request that the ISO expedite consideration of its projects by concluding their evaluation during the 2009 planning cycle.[85]

The ISO continues to take measures to improve transparency in the transmission planning process. For example, The ISO subsequently amended its BPM to expressly provide for public notice to parties submitting proposed project to the ISO of management decisions on such proposals.

b. The ISO's Conclusions and Recommendations about the TTS Proposals were Straightforward and Consistent with Tariff Requirements.

Although the ISO had concluded that, from a legal standpoint, it could not require Participating TOs to enter into a lease with TTS (or any other specific vendor), the ISO nonetheless evaluated the TTS proposals to explore whether it should direct the Participating TOs to install SVC equipment (including entering into leasing arrangements for such equipment voluntarily) as a mitigation solution to resolve short-term reliability concerns. The ISO also compared the lease costs with the long-term solutions proposed by the Participating TOs, despite the fact that it was unclear, at best, whether leasing SVC equipment was being proposed as an alternative to these long-term solutions or as the "interim" solutions which TTS claimed they were in its request window submission forms.[86]

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85 Attachment I, TTS comments.

86 Didsayabutra affidavit at ¶8

The analysis of the TTS proposals, set forth in the amendment to the 2009 Transmission Plan, was straight-forward and based on the ISO's analysis of the study scenarios included with the TTS submission packets, the Participating TOs' request window submissions, and the studies conducted by the Participating TOs at the direction of the ISO. Contrary to the implication in Ms. Mueller's affidavit and the complaint, the ISO did not solicit additional information from the Participating TOs or make adjustments to its study assumptions during the evaluation period prior to the release of the amended transmission plan.[87] Rather, the ISO simply lined up the TTS proposals with the long-term mitigation solutions submitted through the request window in a table set forth at page 294-297 and then set forth conclusions from that table.[88]

In the far left column of the table, the ISO identified the general area of the ISO grid in which reliability concerns had been identified and solutions proposed by TTS and the Participating TOs. The next column described the concern – potential under-voltage situations or thermal overloads – and the year in which the concern was first identified. The request window solutions — both from TTS and the Participating TOs — were identified and described in the columns labeled "Project Name" and "Project Scope." In the "Capability" column, the ISO described the reliability concern that would be addressed by each proposed

87 *Id.*

88 See Attachment D, amendment to the 2009 Transmission Plan.

project. The final two columns set forth the comparative costs of each proposal and the proposed implementation dates for the proposals.[89]

Several conclusions can be drawn from the table. In the PG&E service territory, the long-term mitigation solutions that PG&E proposed through the request window would be implemented within eight months of the TTS implementation date in the Old River and Kern, California and West Fresno, Garberville and Maple Creek areas. Incurring the costs of a five year lease of SVC equipment made little sense in light of this minimal month "gap."[90] Similarly, the "gap" between the TTS and PG&E proposals for the Santa Cruz area was 14 months and the "gap" for Watsonville was 19 months.[91] The PTO proposed solutions were submitted into the ISO request window on October 15, 2008 and they were discussed, in detail, at the November 20, 2008 stakeholder meeting.[92] TTS submitted its proposed solutions on December 15, 2008. Thus, TTS, when it submitted its proposed solutions, should have been aware of the nature of the PTOs' submissions. TTS stated in its request window submissions that its projects were intended as interim projects until the PTO long-term solutions were placed in service. Even though the "gaps" between the in-service

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89 It should be noted that according to the TTS submission packet, October, 2010 was listed as the in-service date but November 15, 2010 was expected to be the commercial operation date for the proposals. The plan amendment listed the earlier October, 2010 as the "in-service" date.

90 The TTS submission packet provided no information as to what the yearly/monthly costs of a lease would be if entered into for a shorter period of time than five years. See Attachment A, TTS request window applications.

91 The amendment references to different "gap" periods for Watsonville, West Fresno, Garberville and Maple Creek inadvertently overlooked the October, 2010 implementation date for the TTS proposal and calculated the "gap" from the date of the reliability concern.

92 See November 20, 2008 PG&E, SCE and SDG&E slide presentations at http://www.caiso.com/1ca5/1ca5d8334b920.html

date of the TTS projects and the PTO projects only ranged from 8-19 months, the TTS proposals were for minimum five-year minimum leases. In other words, TTS was proposing minimum lease terms that would have continued well after the permanent solutions had been placed in service and there was no longer any need for the SVC equipment. Obviously, that was not a cost-effective solution.

Furthermore, the PTO long-term solutions were more-cost effective (as discussed below) and, in several instances, multiple reliability concerns were addressed by these projects.[93] Nonetheless, for the Old River, Camp Evers, Watsonville, West Fresno, Garberville and Maple Creek Interim Solutions, the ISO noted that leasing SVC equipment could fill the interim "gap." This would have required PG&E to voluntarily enter into negotiations with TTS (or any other SVC vendor) for leases with shorter terms. Of course, as discussed below, there were other means by which the reliability "gap" could be addressed, such as via operating procedures and other protective schemes that would not be submitted through the request window. The discussion in the 2009 Transmission Plan amendment was intended to put the participating TOs on notice that the "gaps" needed to be addressed and that leasing SVC equipment was one available option.[94]

PG&E did not propose a long-term solution for the Trinity area. The ISO noted that negotiations were under way between PG&E and the Trinity Public Utilities District ("Trinity PUD") to transfer load from PG&E, but also stated that an

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93 The specific cost analysis for each TTS proposal is discussed below.

94 DeShazo Declaration at ¶ 11-12

interim solution for the identified reliability concerns was needed for this area. Again the ISO commented that leasing SVC equipment could provide an interim solution.

The ISO found no interim reliability need for the Shepherd Interim Solution.[95] For the Cal Cement Interim Solution, the ISO determined that SCE was in the process of developing a comprehensive long term solution but that SVC equipment leasing could present a "gap" solution. For the SDG&E area, the ISO determined that the Barrett Interim Solution was not a feasible mitigation solution.

By amending the transmission plan, the ISO intended to convey four concepts regarding the disposition of the TTS proposals: 1) upon reviewing the technical studies performed by the ISO and the Participating TOs, the ISO identified reliability concerns on both the PG&E and SCE networks; 2) facilities-based mitigation solutions had been submitted through the request window by PG&E (for all but the Trinity area) and by TTS (for the near-term periods); 3) the PG&E long-term solutions (identified in earlier versions of the transmission plan) were more cost-effective than the five year SVC lease proposed by TTS and therefore should move forward to implementation; and 4) although the ISO did not have the tariff authority to require participating TOs to enter into good-faith negotiations with TTS, *voluntarily* leasing SVC equipment (from any vendor) on a short-term basis did present a mitigation solution for the "gaps."[96] These findings

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95 Attachment D; amendment to the 2009 Transmission Plan at 298.

96 Deshazo declaration at. ¶¶ 11-12.

were entirely consistent with the tariff Section 24.1.2 requirements that the ISO (1) coordinate with its participating TOs to identify the need for transmission upgrades or additions; (2) consider (possible) lower cost alternatives such as reactive support; (3) provide an opportunity for interested parties to submit proposals through the request window; and (4) approve specific transmission upgrades and additions for which the applicable participating TO with a PTO Service Territory would be the responsible.

3. The Short-Term Mitigation Solutions Adopted by the Participating TOs Satisfy Applicable Reliability and ISO Grid Planning Standards.

Before turning to a discussion of the individual TTS proposals and the short-term mitigation solutions adopted by the Participating TOs, Ms. Mueller generally asserts that the ISO violated BPM Sections 2.1.2.3 and 3.3.6.1 by not documenting "deviations" from the preliminary results of its planning studies and the duration and frequency of load dropping events.[97] Ms. Mueller also contends that under the ISO's Grid Planning Standards, load dropping solutions for Category B contingencies must be approved by the ISO Board, following stakeholder notice, and therefore the ISO violated the Grid Planning Standards by not obtaining Board approval for the temporary load dropping schemes implemented by PG&E for the interim periods before the capital projects could be constructed.[98] These general statements, apparently based on the October 22,

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97 Mueller affidavit at ¶¶ 25 and 26. Note that paragraph 26 contains an incorrect reference to Section 3.**2**.6.1.

98 Mueller at ¶¶ 28-31.

2009, letter PG&E sent to FERC enforcement staff in response to a call from TTS,[99] are inaccurate and misplaced.

Section II.4.A of the ISO Grid Planning Standards (adopted in February, 2002) addresses circumstances where the ISO has found that the costs of a long-term, facilities-based solution to address a reliability performance problem resulting from an identified Category B disturbance far exceed ratepayer benefits, such that an involuntary load dropping procedure constitutes the preferred approach. For each of the TTS proposals, with the exception of the Trinity area (where the load was leaving the ISO Balancing Authority Area), PG&E proposed capital projects to address the reliability performance concern — low voltage or thermal overloads following a Category B contingency – on a permanent basis. PG&E did not propose to interrupt load as an alternative to a facilities-based permanent solution to the identified reliability performance concern. The ISO accepted the permanent solutions which involved constructing new transmission upgrades, none of which involved load dropping. No consideration of alternative load interruption solution occurred, and Section II was thus not implicated. In addition, as discussed below, the interim solution proposed by SCE for the Bailey-Antelope area did not involve load dropping. Similarly, there are transmission solutions in the areas of WGD's proposed projects where was an immediate reliability need in response to an identified Category B contingency. All of the ISO's recommended solutions were presented to stakeholders and the Board. Accordingly, because the ISO did not approve

99 Mueller at ¶¶ 36, 41, 46, 51, 55 and 64; see PG&E letter at Attachment M to the complaint.

load interruptions as long-term “planning solutions,” the Grid Planning Standards process for providing stakeholder notice and seeking Board approval for load dropping was not triggered and is inapplicable to the analysis of the TTS and WGD proposals.

Section V. of the Grid Planning Standards provides the background behind the adoption of Section II.4 and describes this standard as pertaining to new transmission versus involuntary load interruption. Section V also describes a series of steps that the PTOs were to follow to implement this new standard, including the notification step to which Ms. Mueller refers in her affidavit. However, most of the steps contemplated in Section V no longer occur under the ISO’s transmission planning process because they were eliminated from the tariff as part of the ISO’s compliance with Order No. 890, which was approved by the Commission, subject to a compliance filing, in June, 2008.[100]

Specifically, Section V of the Grid Planning Standards contemplates that the following process will be used. As part of their evaluation of alternatives, in their Five Year Transmission Expansion Plans, the PTOs will propose either projects or operating procedures for involuntary load shedding as the appropriate solution to address identified reliability criteria violations.[101] The ISO, with input from the PTOs and stakeholders will review the PTO’s five-year plans and determine whether to adopt the PTO’s proposed transmission projects or operating procedures and the final ISO-approved plan will be distributed to

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100 *California Independent System Operator* Corporation, Order on Compliance Filing, (June 19, 2008),123 FERC ¶61,283.

101 *See* Section V.3 of the ISO Grid Planning Standards.

stakeholders.[102] Requiring the involuntary load dropping analysis to be included in the PTO's five year plans was consistent with the ISO's previous tariff section 24, but that section was substantially revised as part of the ISO's Order No. 890 compliance filing, including eliminating the entire requirement that PTOs develop "Five Year Transmission Expansion Plans."

Therefore, the pre-condition (as well as several other steps) in the process for implementing the Grid Planning Standard's standard regarding new transmission versus involuntary load dropping were eliminated in the Order No. 890 compliance process. Given that the PTOs no longer are required to submit Five Year Transmission Expansion Plans which, among other things, would identify areas where the PTOs would propose load shedding operating procedures in lieu of building transmission upgrades, the process specified in the Grid Planning Standards for implementing the standard regarding new transmission versus involuntary load dropping no longer "works." The ISO notes that the Grid Planning Standards do not contemplate situations where non-PTOs are proposing transmission projects in lieu of load shedding. The Grid Planning Standards are outdated and out of synch with the provisions of the ISO tariff governing transmission planning approved by the Commission first as part of the ISO's efforts in compliance with Order no. 890 and more recently revised to implement the ISO's revised transmission planning process.

The ISO's Order 890 transmission planning process provides stakeholders with many more opportunities for participation, comment, and review of project

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102 *Id.* at Section V.6.

proposals and underlying study assumptions (among many other process enhancements) than were available at the time the Grid Planning Standards were adopted. Indeed, the steps outlined in Section V. have largely been subsumed by the ISO's multi-stage annual planning process. Nonetheless, the ISO commits to working with stakeholders to review the Grid Planning standards for needed updates and to address this matter in 2011.

Ms. Mueller repeats her arguments that the ISO "violated the TPP" by not "approving the TTS project" and "choosing to drop load without Board approval or notice with respect to each of the individual TTS proposals, as well as generally in the beginning of her affidavit."[103] The ISO has responded to these assertions in this section and will not repeat its arguments and factual responses for each of the TTS proposals addressed below.

As to "deviations from the planning assumptions,"[104] the ISO assumes that Ms. Mueller is referring to the short-term operating procedures adopted by the PTOs for the interim periods before the long term capital solutions are in service. Based on that assumption, Mr. Didsayabutra explains in his affidavit that these short term operating procedures do not constitute changes in the planning assumptions used by the ISO in studying the TTS projects.[105]

Ms. Mueller also makes the statement that the ISO violated Section 3.2.6.1 of the BPM by not documenting the amount of "interruptible Load" that the PTOs intended to shed and "the duration and frequency" of such load shedding

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103 *Id.* at ¶¶ 39, 44, 49 and 58.

104 Mueller affidavit at 25.

105 Didsayabutra declaration, par. 10.

(this BPM section reference should have been to 3.3.6.1).[106] This argument is wide of the mark. Both that BPM section and tariff section 24.3.1 refer to the identification of interruptible Load as part of the total Demand information provided by PTOs. In that context, "interruptible Load" is intended to refer to voluntary load shedding arrangements in which customers are compensated for agreeing to be interrupted under certain network conditions.

a. Maple Creek Interim Solution

Ms. Mueller correctly states that both PG&E and TTS submitted projects through the request window to address Category B and C low voltages in the Maple Creek area, and that the ISO found the PG&E long-term solution to be the more cost-effective approach.[107] As discussed above, the implementation date for the PG&E permanent project was May, 2011, and the commercial in-service date for the TTS project was October, 2010, leaving an eight month "gap" where there was an identified reliability performance issue.[108] Ms. Mueller then points to the October 22, 2009, letter from PG&E and describes the PG&E's mitigation solution for the interim period as an "interruption of all electric customers served from the Maple Creek, Russ Ranch, Willow Creek and Hoopa substations" in the event of a Category B outage of the Humboldt-Maple Creek line.[109] At paragraph 37 she identifies "two fundamental problems" with this characterization

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106 Mueller affidavit at 26.

107 Mueller affidavit at ¶ 34.

108 Assuming the commercial operation date of November 15, 2010, the gap would be seven months.

109 Mueller affidavit at ¶ 36.

of the PG&E response: it was submitted "outside of the TPP and the request window" and "load dropping in lieu of building transmission" must be approved by the ISO Board.

In the first place, Ms. Mueller misunderstands the PG&E interim solution. The interim mitigation solution in response to low voltages on the Humboldt-Maple Creek line is to disable the automatic switching during the summer peak load periods that is intended to recover load that has already been dropped after the radial line is lost (the single contingency). In this situation, the loss of Humboldt-Maple Creek 60 kV line will result in a brief loss of load at Maple Creek, Russ Ranch, Willow Creek, and Hoopa.[110]

A sustained fault on the Humboldt-Maple Creek 60 kV Line would disconnect Maple Creek, Russ Ranch, Willow Creek, and Hoopa substations, circuit breakers #22, 42, and #92 would open and isolate the fault. PG&E has installed a motor operated switch (at M 97 on the diagram) that enables PG&E to restore these loads by isolating any sustained fault on the Humboldt-Maple Creek 60 kV Line. Using automatic switching, it would take about 30 to 60 seconds to restore service to the Maple Creek, Russ Ranch, Willow Creek and Hoopa substations. However, during peak load periods, this automatic switching could lead to low voltage situations in certain circumstances.[111] The ISO has approved a capital project to install reactive support as a long-term solution in

110 Didsayabutra declaration, ¶11.

111 *Id.*, ¶. 13.

lieu of load dropping.[112] For the interim eight month "gap" before reactive support is installed, PG&E will disable the automatic switching of Maple Creek circuit breakers and switch to prevent low voltage conditions during high peak demand periods.[113] Depending on system conditions, PG&E operators could manually restore service by remote operation.

PG&E was not required to submit this interim procedure through the transmission planning process request window. In that regard, Section 24.2.3 of the Tariff does not require operating procedures and other similar mechanisms designed to maintain the day-to-day reliability of the ISO grid to be submitted through the request window. The tariff only requires that transmission upgrades and additions be submitted through the request window and be approved by ISO Management or the Board.[114] This interim solution is neither. Furthermore, even if the manual load switching procedure followed after the fault has been isolated on the Humboldt-Maple Creek line could be considered to be "load shedding," which it is not, it is not a permanent solution for the identified reliability performance contingency and therefore it is not the ISO's "planning" solution to the low voltage concern. Rather, the ISO's "planning" solution is the installation of reactive support so that the automatic switching does not need to be disabled.

Interestingly, PG&E's permanent solution for the Maple Creek and Garberville areas – to install reactive support equipment – is similar to the TTS

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112 *Id.,* ¶11.

113 *Id.*, ¶ 13.

114 See Section 24.2.4.

proposal.[115] However, the MVAR capacity of the SVC equipment selected by PG&E to address the reliability concerns is much smaller than the equipment proposed by TTS, and as a result the cost of the PG&E solution is lower than the cost of the TTS solution. As reflected in the amended transmission plan at page 296, the PG&E long term solution for Maple Creek was to install a 10 MVAR SVC at the Maple Creek substation. TTS proposed to lease PG&E a -40/+50 MVAR SVC at Maple Creek to address the same concern on an interim basis. TTS' proposed MVAR capacity was excessive and more than what was needed to address the reliability concern. Thus, had PG&E decided to voluntarily lease SVC equipment for eight months (for the "gap"), the size of the equipment being offered by TTS would have been was excessive for resolving the identified reliability concern.[116]

b. Old River Interim Solution

Ms. Mueller's discussion of the Old River Interim Solution (paragraphs 40-44) is similar to the Maple Creek discussion except for her assertion that the ISO "erroneously" found the PG&E long-term solution to be more cost-effective than the TTS SVC lease.[117] She also speculates, without providing any support or evidence, that an outage of the Kern-Old River No. 1 line would involve load shedding.[118]

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115 However, PG&E has not proposed to install the same equipment offered for lease by TTS. See Didsayabutra at ¶ 11

116 *Id.*

117 Mueller affidavit at ¶ 40.

118 *Id.* at ¶ 41.

For the Old River and Kern areas, the PG&E long-term solution involves reconductoring 35 miles of Kern-Old River 70 kV lines 1 and 2. This solution resolves the identified thermal overloads and improves voltage in the area. The ISO found that the TTS proposal could improve voltage in the area, but could not mitigate thermal overloads beyond 2010.[119] Also taking into consideration the October, 2010, implementation date for the Old River Interim Solution, this TTS proposal had limited usefulness in mitigating reliability concerns in the area.[120] PG&E's reconductoring solution would be implemented by May, 2011, so the entire interim "gap" spanned eight months, and the TTS leased equipment would only be useful for about three months (the period of time between the in-service date of the TTS proposal, October, 2010 and January, 2011, when the project was not likely to address forecasted thermal overloads and another solution would be needed). Furthermore, as discussed in greater detail below, the five year leasing arrangement did not present a more cost-effective solution, particularly because the TTS proposal did not resolve all reliability concerns. In fact, if the TTS proposal were to be adopted, the remaining thermal overloads would still need to be addressed by capital transmission upgrades (the costs of which TTS failed to consider).

The PG&E interim solution is similar to the procedure put in place for the Maple Creek area. According the line diagram in Mr. Didsayabutra's declaration, when a sustained fault occurs on Kern-Old River 70 kV line no. 2, circuit breakers

119 Attachment D, amendment to 2009 Transmission Plan at 297.

120 Didsayabutra affidavit at ¶ 14.

Nos. 42 and 32 would open to isolate the fault. PG&E has installed two motor operated switches (Nos. 21 and 23) at the junction point where Panama substation connects to Kern-Old River 70 kV No. 2 lines. These switches enable PG&E to restore electric service to Panama substation. For example, once the fault occurs between Kern Power Plant and Panama, the Kern Power Plant Circuit Breaker No. 42 and the Panama Switch No. 21 would remain open. Service will be restored to load served from the Panama bus by closing the switch M 23 and circuit breaker number 32. The restoration switching sequence would take about 30-60 seconds. In response, during summer months PG&E will disable the restore feature on Panama switch no. 23. Once again, such a procedure is not considered "load shedding" subject to the ISO grid planning standards.[121]

c. Watsonville Interim Solution

The PG&E long term solution for the Watsonville area – converting Watsonville 60 kV to 115kV and connecting a new system into the Green Valley and Crazy Horse 115 kV projects – will alleviate thermal overloads, low voltages and potential loss of customer (under Category C conditions) in this local area. The TTS proposal would address only the Category B under voltage conditions.[122]

Furthermore, the TTS cost analysis presented by Mr. Alaywan suggested that a ten year TTS leasing arrangement would allow the PG&E long-term

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121 Didsayabutra Declarations at ¶15

122 Attachment D, amendment to the 2009 Transmission Plan at 297.

solution to be deferred and would be more economical for ratepayers. Ms. Mueller also proposes, as a general "remedy" for all of the TTS proposals, that deferral of the long-term solutions (in combination with a long-term TTS lease) be analyzed, presumably using the cost methodology described in Mr. Alaywan's affidavit.[123] Mr. Alaywan's flawed economic methodology is discussed below. However, the proposal to defer the PG&E long-term solution also shows a major flaw in the TTS engineering analysis for the Watsonville interim solution.[124] The TTS study focuses narrowly on low voltage in a small area without considering negative impacts that could result from deferring the long-term project by PG&E. As part of its scope, the PG&E conversion project is designed to address thermal overloads, low voltages and potential loss of customers (under Category C conditions- double circuit tower line outage) in a larger area. According to the PG&E 2008 Electric Transmission Reliability Assessment Study for the Central Coast and Los Padres area, unless the Watsonville Voltage Conversion Project is in-service, a double circuit tower line outage (Category C) of the Moss Landing – Green Valley lines could result in over 60,000 customers in Santa Cruz County being without power until one line can be restored. In addition, the Moss Landing – Green Valley 115 kV Line can be overloaded following the outage of Moss Landing – Green Valley No.1 115 kV Line and the CIC Cogen unit.[125]

Therefore, the PG&E permanent solution project will create a stronger 115 kV connection to Green Valley 115 kV substation, which will alleviate power flow

123 Attachment 1 to Mueller affidavit

124 Didsayabutra Declaration at ¶ 17.

125 Didsayabutra Declaration at ¶. 17

on the Moss Landing-Green Valley 115 kV Lines that results in lower loading on these lines under both normal and emergency conditions. Consequently, with the Watsonville voltage conversion project, potential overloads on Moss Landing-Green Valley 115 kV lines that were identified in PG&E study can be averted. The voltage conversion project also mitigates the risk of customers being without power due to the double circuit tower line outage. [126] The TTS proposal to defer the project would result in reduced reliability of the system, requiring other solutions to be implemented in parallel with the TTS solution.[127]

With respect to the interim period, TTS acknowledged in its request window submission packet that an under voltage load shedding (UVLS) protective scheme was in place for this area.[128] Although the ISO advised PG&E, through the amendment to the transmission plan, that a short term lease of SVC equipment had been submitted through the request window and was available for consideration as an interim solution, PG&E chose to continue to rely on the UVLS. This protective scheme was developed during 2001 has been in place since mid- 2002 as an acceptable solution.[129]

Ms. Mueller's argument that the ISO "should have gone to the Board" with the existing UVLS has no merit, as discussed in more detail above. PG&E proposed a permanent solution for the under voltage condition that was approved

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126 *Id.* at ¶18.

127 As discussed in Section 4 below, deferring the PG&E long-term solutions were not part of the TTS request window submissions and were introduced as part of this complaint.

128 See Attachment A, Watsonville Interim Solution request window application.

129 Because a long-term solution had been approved and would be implemented by May, 2012, the UVLS would remain in effect longer for only a short period of time and therefore is the "interim solution in these circumstances.

by the ISO in the transmission plan, so PG&E was not proposing to drop load in lieu of building a permanent transmission solution. Thus, once again, the notice and Board approval sections of the Grid Planning Standards are not implicated.

d. Garberville Interim Solution

Ms. Mueller correctly explains that the interim solution adopted by PG&E for the Garberville area for the eight month reliability "gap" between the proposed implementation of the TTS leasing arrangement and the permanent installation of SVC equipment was to follow an operating procedure that permits an increase in the regulator setting on the Mendocino 115/60 kV transformer.[130] She first argues that this procedure was submitted "after the fact" and "outside of the TPP." She then claims that this change in regulator settings would obviate the need for PG&E's long-term solution, implying that the ISO should have simply approved the operating procedure as the long term solution.[131] Ms. Mueller is incorrect on both counts.

As noted above, there is no tariff or BPM requirement that operating procedures and similar protective schemes that do not involve capital transmission project upgrades or additions must be submitted through the request window. This particular operating procedure has been in effect in PG&E's Fulton control center since mid-2009.[132]

This regulator adjustment would be made in the event that low voltage conditions at Ridgeville, Fruitland, and Fort Stewart substations are projected. In

130 Mueller at ¶ 51

131 *Id.* at ¶ 53.

132 Didsayabutra Declaration at ¶ 20

this scenario, PG&E would increase regulator settings on the Mendocino 115/60 kV Transformer Nos. 1 and 3 in response to low voltage situations. However, the Mendocino transformer is more than 70 miles away from the Garberville bus and therefore the regulator adjustment solution is only a temporary solution until the permanent solution approved by the ISO – the Garberville reactive support solution -- can be put in place. From an engineering and reliability standpoint, Ms. Mueller's suggestion that this interim solution be made into a permanent solution[133] is flawed and should not be seriously considered. The installation of reactive support equipment at the Garberville substation resolves these reliability concerns permanently and more effectively than the TTS proposal.[134]

e. Camp Evers Interim Solution

In a manner similar to description of the Maple Creek and Old River interim solutions, Ms. Mueller describes the PG&E interim mitigation solution as load dropping schemes subject to the Board approval and notice requirements of the ISO's grid planning standards.[135] Once again, load dropping is not PG&E's "planned" permanent solution to low voltages following a NERC Category B contingency. Rather, the ISO has approved a long-term permanent solution to address low voltages in the area – the Santa Cruz 115kV reinforcement project –

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133 *Id.* at ¶20-21.

134 As noted above, TTS proposed to lease SVC equipment that was sized inappropriately for the reliability concerns in this area. Note that in the amendment to the 2009 Transmission Plan, Attachment D, at page 298, the projects for the Garberville area incorrectly refer to reactive support being installed at the "Maple Creek substation." That reference should have been to the "Garberville substation." PG&E has proposed to install different sized SVC equipment in the Maple Creek and Garberville substations whereas TTS proposed the same size for both buses.

135 Mueller affidavit at ¶¶ 55 and 57.

that will be implemented 14 months after the TTS interim solution would have been implemented and at a much lower cost than a five year lease.[136]

The PG&E interim solution was implemented in 2005 when PG&E installed two motor operated switches at the junction point where the Rob Roy substation connects to the Green Valley-Paul Sweet 115 kV line as shown on the line diagram in Mr. Didsayabutra's declaration.[137] A sustained fault on the Green Valley-Paul Sweet 115 kV line would open circuit breakers A, B, disconnecting load at Rob Roy These switches enabled PG&E to restore electric service to Rob Roy by isolating any sustained fault on the Green Valley-Paul Sweet 115 kV line and reclosing the circuit breaker and switch to restore the load. However, a sustained fault on the Green Valley-Paul Sweet 115 kV line together with the outage of Paul Sweet STATCOM would disconnect Rob Roy substation from the grid.

Consequently, for the short period of time before the permanent solution is implemented, PG&E has implemented an interim solution to mitigate these issues. If and when the Paul Sweet STATCOM is out of service during winter months, PG&E will manually switch in the 21 MVAR station capacitors at Paul Swett, as needed, to raise the voltage level. If the station capacitors are unavailable, or if PG&E operators or the ISO still have concerns about low voltage, PG&E would manually disable automatics on the Paul Sweet circuit breaker No 162. Reliance on this interim solution is very short since the

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136 See Attachment D, amendment to the 2009 Transmission Plan, at 297. See also Didsayabutra declaration, ¶. 22.

137 Didsayabutra declaration, ¶. 23.

expected in-service date of the Santa Cruz 115 kV Reinforcement project is December 2011.[138]

f. Cal Cement Interim Solution

In the Antelope-Bailey area of the SCE service territory, the ISO identified potential Category B voltage deviation at several 66 kV substations. At the time the Cal Cement Interim Solution was evaluated, SCE was in the process of developing a long-term mitigation solution that would be operational in 2011.[139] The TTS proposal was identified as a possible short-term mitigation solution for the "gap" prior to implementation of the permanent solution. Assuming that the TTS proposal would become operational in October, 2010, the projected reliability "gap" for this area was approximately 14-15 months.

Without providing any support, Ms. Mueller speculates that the SCE interim solution for this area is either that "the ISO will not be meeting reliability criteria," or "they plan to drop load in response to a Category B contingency."[140] In actuality, however, SCE implemented an operating procedure to address the interim gap, and it does not involve load dropping.[141] This operating procedure, OP 068, would curtail the output of generation resources in the area to mitigate potential overloads and voltage concerns that were identified without dropping the load. As indicated above, there is no requirement that this program be submitted through the request window or approved through the transmission

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138 Didsayabutra Declaration at ¶ 24-25..

139 Attachment D, amendment to the 2009 Transmission Plan, p. 298.

140 Mueller affidavit at ¶ 60.

141 Didsayabutra Declaration at ¶27

planning process. Furthermore, a long term solution for the under-voltage concerns in the area was approved in the 2010 cycle as part of the East Kern Wind Resource Area (EKWRA) 66 kV reconfiguration.[142]

g. Trinity Interim Solution

In the 2009 Transmission Plan amendment, the ISO identified Category B under voltages at the Trinity substation beginning in 2009. In the narrative description at page 298, the ISO noted that PG&E had entered into discussions with the Trinity PUD to transfer load served at the Trinity substation, thus addressing the reliability concern. Although the ISO anticipated that the load would be transferred by April, 2010,[143] the ISO suggested in the transmission plan that the TTS proposal could provide an interim during any "gap" period that might occur if these negotiations did not conclude as anticipated.[144]

Nonetheless, the ISO recognized that once these negotiations had concluded, the Trinity PUD load would no longer be in the ISO Balancing Authority Area and would not be served by the PG&E facilities that are part of the ISO-Controlled Grid. The ISO included this information in both the 2009 Transmission Plan[145] and the 2010 Transmission Plan,[146] describing the Trinity

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142 *Id.*

143 Micsa Declaration at ¶¶ par. 8

144 It should be noted that in her affidavit Ms. Mueller mischaracterizes the "gap" period by stating that the TTS proposal would "meet ISO identified NERC Category B under voltage concerns in the Trinity area beginning in 2009." In fact, the TTS proposed in service date for its lease arrangement was October, 2010, so under voltage conditions in 2009 would not have been addressed by this proposal.

145 See Attachment M, page 81 of the draft 2009 Transmission Plan.

146 See Attachment N, page 80 of the 2010 Transmission Plan.

area reconfiguration as a project being undertaken by the Western Area Power Administration ("WAPA") project in an adjacent control area that would result in the Trinity PUD load being served by WAPA and not PG&E. Because this undertaking was a WAPA project that was not part of the ISO Controlled Grid. It did not require ISO approval and was not required to be submitted through the request window as a mitigation solution.[147]

In fact, the Trinity area reconfiguration was placed in service in May 2010 and it addressed all reliability criteria concerns in the area. The project has removed all loads in the area – Mill Station (Weaverville), Douglas City and Hayfork – from the ISO grid and into the neighboring control area without any normally closed ties between the ISO control area and the neighboring control area in this vicinity.[148] Because the TTS interim proposal for this area could not have been implemented before October, 2010 and the load was transferred prior to that date, there was no need for the proposal.

In her affidavit, Ms. Mueller focuses on the short-term solution for the Trinity area described in the PG&E October 22, 2009 letter to FERC staff and ignores the load transfer discussions described by the ISO in the amended 2009 Transmission Plan and in previous plans.[149] The PG&E statement in the October 22, 2009 letter about reduced loads in the Trinity area in 2009 has no relevance to this discussion because the TTS proposal was not available in 2009

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147 Although stakeholders had information about the proposed load transfer, it was not modeled in the transmission planning base cases because it was not included in the WECC base cases by the neighboring control area. See Micsa Declaration at ¶6.

148 *Id.*

149 Mueller affidavit at ¶¶ 63-67.

as an interim solution. As indicated above, TTS proposed an in-service date of October 15, 2010 for its leasing solution. The reliability concerns in the Trinity area that were identified in prior reliability assessments were permanently resolved before that date.

4. The TTS Proposals Were Not Cost-Effective Mitigation Solutions.

TTS made it very clear, both in its request window submission packets and the comments submitted by Ms. Mueller, that the TTS proposals were "interim" projects that would resolve short-term reliability needs until the permanent facilities-based mitigation solutions submitted by the participating TOs could be implemented.[150] However, what was never made clear is how the "costs" of the leasing arrangement would be calculated under various lease lengths (except for five years), and what kind of cost comparison the ISO should undertake in determining whether these costs were reasonable. TTS was obviously confounded by this issue as well, because, in the request window submissions, each proposal was described as having a lower revenue requirement than the Participating TO solution, but in the complaint Mr. Alaywan only states that two TTS proposals – the Old River Interim Solution and the Watsonville Interim Solution – provide any ratepayer benefits over the competing solution.[151]

a. The Economic Analysis Submitted with the TTS Request Window Packets Provided No Useful Cost Information.

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150 *See* request window submissions at Attachment A; Mueller Affidavit at Attachment I

151 *See* Attachment A, TTS request window applications, Alaywan affidavit at 31.

Each TTS project submission packet included an Exhibit A entitled "Legal and Policy Basis for Applicant's Proposed Solution." [152] This attachment, which is identical for each project and refers to "PG&E" even when submitted with the projects in SCE's territory, contained a very unclear description of the TTS proposal and raised more questions than it answered. For example, the first page contains the statement that "by selecting Applicant's solution for the Site, PG&E's RW solution would be mooted." That paragraph goes on to describe the PG&E "proposal" as entailing "direct and permanent ownership of a "Device" (defined as FACTS SVC equipment) at the Site." Later in the document, at page 3, TTS makes the statement that "Applicant has been informed by PG&E that, in its competing RW application, it proposes to appropriate the technical solution developed by Applicant, but to link it to traditional utility financing techniques which are far less suitable for the purpose." In other words, it appears that TTS was under the mistaken impression, when its request window packets were submitted on December 15, 2008, that PG&E (and SCE and SDG&E) were also going to propose *the same* reactive support device in the same locations. [153] Of course, TTS easily could have avoided this error because PG&E and the other

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152 See Attachment B. This document was discussed above with respect to tariff Section 24.1.2 and the ISO's legal position.

153 See the following language from Attachment B at page 4:

> It is only recently that PG&E's lead engineer has informed Applicant has decided unilaterally to seek to install the Device on its own and include it as part of the r ate base.

"Device" in that sentence refers to the TTS proposed FACTS equipment. Again, this exhibit was attached to all of the request window submissions, including those submitted in the SCE and SDG&E service territories. Based on that statement, it can be inferred that TTS assumed that all three PTOs were going to install the same device to resolve of the reliability concerns at every location.

Participating TOs were required to submit their reliability projects on October 15, 2008, well before the last day of the request window (when TTS submitted its projects). In the 2008-2009 planning cycle, the stakeholder meeting at which the Participating TO reliability projects, including implementation dates, were presented to stakeholders was held on November 20, 2008.[154]

Based on the premise that the participating TOs intended to install the same SVC equipment to resolve all of the identified under-voltage situations, the cost analysis of the lease submitted with each packet makes some sense but nonetheless presented very little useful information. For each location, the costs of a five year lease were calculated in terms of a TTS "revenue requirement" for each year compared to the revenue requirement of the Participating TO for the same equipment. For example, the tables below reflect the cost comparison calculation provided to the ISO for the Old River Interim Solution.[155].

The first is the project cost calculation for the TTS proposal, as calculated by TTS using the "ratemaking assumptions" in the second table:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 495,000	$ 1,182,500	$ 1,089,000	$ 660,000	$ 3,426,500	$ 3,162,665
1	$ 10,505,000	$ 495,000	$ 1,129,288	$ 1,039,995	$ 630,300	$ 3,294,583	$ 3,162,665
2	$ 10,010,000	$ 495,000	$ 1,076,075	$ 990,990	$ 600,600	$ 3,162,665	$ 3,162,665
3	$ 9,515,000	$ 495,000	$ 1,022,863	$ 941,985	$ 570,900	$ 3,030,748	$ 3,162,665
4	$ 9,020,000	$ 495,000	$ 969,650	$ 892,980	$ 541,200	$ 2,898,830	$ 3,162,665
						$ 15,813,325	

154 See November 20, 2008 PG&E, SCE and SDG&E slide presentations at http://www.caiso.com/1ca5/1ca5d8334b920.html

155 See Attachment A; each request window application contains a similar table.

Ratemaking Assumptions	TTS Costs
Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Cost of Capital	10.75%

The following is the TTS calculation of PG&E's costs to install the same SVC equipment, using the PG&E "ratemaking assumptions" in the second table:

PG&E Cost							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 495,000	$ 1,019,700	$ 1,969,000	$ 803,000	$ 4,286,700	$ 3,945,447
1	$ 10,505,000	$ 495,000	$ 973,814	$ 1,880,395	$ 766,865	$ 4,116,074	$ 3,945,447
2	$ 10,010,000	$ 495,000	$ 927,927	$ 1,791,790	$ 730,730	$ 3,945,447	$ 3,945,447
3	$ 9,515,000	$ 495,000	$ 882,041	$ 1,703,185	$ 694,595	$ 3,774,821	$ 3,945,447
4	$ 9,020,000	$ 495,000	$ 836,154	$ 1,614,580	$ 658,460	$ 3,604,194	$ 3,945,447
						$ 19,727,235	

Ratemaking Assumptions	PG&E Costs
Capital Cost	11,000,000
O&M (include Insurance)	17.9%
A&G	7.3%
Cost of Capital	9.27%

Because PG&E (and SCE and SDG&E) did not propose to install the same equipment, this revenue requirement comparison provided by TTS was irrelevant. Furthermore, because under the ISO tariff TTS would not have had the authority to build these reliability projects, a "revenue requirement" calculation for TTS makes little sense. Thus, for evaluation purposes, the ISO was left with what appeared to be the "costs" of the lease (apparently to the Participating TO), which was the sum of the five years of "revenue requirement."[156] In the Old

156 The fact that TTS conducted a "revenue requirement" analysis is confusing in and of itself. As discussed above, even if the participating TOs had entered into leasing arrangements

River example above, that cost was $15,813,325, which the ISO compared to the cost of the long term solution proposed by PG&E for the Old River-Kern area.

Because, as noted above, the PTO solutions would have been submitted in the request window approximately 60 days before TTS submitted its proposals, TTS should have known the estimated in-service dates of the PTO's transmission solutions, Nonetheless, TTS proposed a minimum five-year lease for its proposals. The only additional mention of a lease term was the statement that TTS would be willing to extend the lease for a longer period, and then to sell the residual equipment to the Participating TO once it had been fully depreciated.[157] Thus, TTS was seeking a minimum five-year lease even when the gap between the in service date of the long-term solutions and the interim solution proposed by TTS only ranged from 7 to 19 months. Intuitively the arrangement expressly proposed by TTS in its request window submissions makes no sense, but the ISO nonetheless advised the participating TOs, through the transmission plan amendment, that TTS leasing option had been proposed through the request window and that a leasing arrangement might present a short term solution...

b. Mr. Alaywan's Analysis Does Not Support a Finding that the TTS Proposals were Cost Effective Solutions.

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with TTS, it would seem that the lease payments being made to TTS *would be added to the transmission revenue requirement of the Participating TO.* Despite TTS's arguments about becoming a Participating TO, leasing equipment to a participating TO would not provide *the lease vendor* with a transmission revenue requirement that would be recovered through the ISO's transmission access charge; nor would such an arrangement make the vendor eligible to become a PTO.

157 See Attachment A, request window submission applications for each proposal.

In the complaint, and after the fact, TTS has now changed its position with respect to any ratepayer benefits associated with the SVC leasing arrangements and how the cost comparison was supposed to have been conducted. According to Mr. Alaywan, for the Old River/Kern and Watsonville areas, the ISO was supposed to have assumed that PG&E would lease the SVC equipment for ten years and defer its long-term solutions, the costs of which would then be recovered over 25 years. However, that is not what TTS proposed in its request window submissions for these areas.[158] Mr. Alaywan is basically suggesting a brand new TTS proposal, two years after the fact, that was not reflected in TTS request window submission. According to Mr. Alaywan's calculations, somehow adding the costs of a ten year lease to a long-term solution provides more ratepayer benefits than the costs of the long-term solution without the ten year lease. On its face, this conclusion makes no sense – how can adding $15 million to the costs of a project provide reduced ratepayer benefits?

According to Mr. Millar, the ISO's Executive Director, Infrastructure Development, it doesn't. Mr. Millar explains in his Declaration that Mr. Alaywan's NPV calculation, upon which the entire cost/benefit comparison is based, is severely flawed because, among other things, it (1) fails to properly address the different service lives of the projects being analyzed;[159] (2) fails to properly apply consistent discount rates in calculating net present value each project's annual

158 *Id.*

159 Millar declaration at ¶¶. 14-17.

revenue requirement; [160] and, (3) applies inflation to costs inconsistently.[161] Furthermore, Mr. Millar takes issue with Mr. Alaywan's assumptions regarding PG&E's O&M and A&G expenses.[162] These render Mr. Alaywan's analysis of no use to the Commission in the Commission's determinations. The ISO describes other concerns with the proposed economic analysis of the TTS/WGD projects at section F, below.

Even an assumption, *arguendo,* that Mr. Alaywan's cost analysis had any validity, which it does not, would not overcome his failure to consider the fact that the PG&E long-term solutions solve additional reliability problems that leasing SVC equipment did not address.[163] Even if the ISO were to approve the installation of SVC equipment, it still would have had to approve new transmission solutions to address the reliability concerns that the SVC equipment does not address. Mr. Alaywan's analysis fails to account for the added costs that would have to be incurred to address the remaining reliability concerns and which would render a SVC solution not cost-effective. Thus, his analysis is not an apples to apples comparison. Furthermore, TTS provided no engineering analysis as to impacts of deferring the permanent solutions for ten years. Mr. Didsayabutra did conduct such an analysis and concluded that, for the Watsonville long-term solution, additional reliability concerns would be caused by

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160 *Id.* at ¶¶ 18-25.

161 *Id. at* ¶¶ 26-29.

162 *Id. at* 5-12..

163 As described in the amendment, both the Old River and Watsonville long term solutions solve more reliability concerns than the TTS proposals.

a ten year-deferral (see discussion at section C.3.c). Thus, the proposed "remedy" for each of the TTS solutions – that a "deferral analysis" be conducted -- has absolutely no economic or engineering basis and should not be seriously considered. Indeed, it is ironic that TTS accuses the ISO of considering "after the fact" information and "deviations from its planning assumptions" in evaluating the TTS proposals, yet now, two years later, wants the Commission to consider an entirely new cost methodology to accommodate re-framing its proposal, revising the proposal itself, and requesting that the ISO unwind the clock and implement it.

D. WGD's General Allegations Regarding the ISO's Treatment of Its Projects Are Without Merit

1. The Nature of the ISO's Response to WGD's Commits Was the Result of WGD's Failure To Follow the Established Process for Submitting Comments

In her affidavit, Ms. Mueller notes that WGD sent a letter to the ISO on March 2, 2010 discussing the alleged flaws in the ISO's analysis of WGD's storage projects, and states that the letter was not posted by the ISO on its website as required by the BPM.[164] Ms. Mueller also claims that the ISO did not respond to WGD's comments as required by the ISO's tariff and BPM.[165] She does, however, acknowledge that WGD received a letter from the ISO rejecting the issues raised by WGD in its March 2 letter.[166]

164 Mueller Aff. at ¶ 78.

165 *Id.* at ¶ 79.

166 *Id.* at ¶ 80.

As the Commission has recognized in assessing the ISO's compliance with Order No. 719, the steps in the ISO's stakeholder process are outlined on the ISO's website such that stakeholders know at all times where a particular stakeholder process stands, including the entire written record of the stakeholder process.[167] All policy initiatives follow a similar course: the ISO publishes draft documents, provides an opportunity for stakeholders to comment on the draft documents and conducts a stakeholder meeting (either by conference call or in-person) to discuss the status of the stakeholder initiative and enable stakeholders to pose questions to the ISO. These meetings and conference calls are open to all stakeholders.[168] For in-person meetings, held in Folsom, the ISO enables remote participation via a conference call with web-conferencing. This permits all interested stakeholders to participate in ISO stakeholder meetings even if they cannot attend in person. The stakeholder initiative for the 2010 Transmission Plan followed this process.

On February 16, 2010, the ISO held an in-person stakeholder meeting (with a conference call hook-up) in which the ISO discussed the draft 2010 Transmission Plan.[169] That draft transmission plan addressed, among other things, the ISO's proposed treatment of the battery storage projects submitted by

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167 *California Independent System Operator Corporation,* 133 FERC ¶61,067 (2010)

168 Comments of the California Independent System Operator Corporation on February 24, 2010Technical Conference on RTO/ISO Responsiveness at 4-5, Docket No. ER09-1048, March 8, 2010.

169 The stakeholder record for the 2010 California ISO Transmission Plan Initiative can be found at http://www.caiso.com/20a1/20a1dbe417300.html (*See* 2010 ISO Transmisison Plan Stakeholder Meeting, 16 Feb. 2010).

WGD.[170] At the February 16, 2010 stakeholder meeting, the ISO discussed its recommended treatment of proposed projects, including the WGD storage project.[171] The ISO's presentation to stakeholders outlined the next steps in the stakeholder process, the first of which was that stakeholders were to submit comments by March 2, 2010. The ISO informed stakeholders that all comments must be emailed to a specific email address. The ISO's presentation was also posted to the ISO website (as part of the stakeholder record in the 2010 Transmission Plan stakeholder process) and indicates that all stakeholder comments were to be emailed to the specified email address.[172] This is the same email address that the ISO used to receive comments from stakeholders throughout the entire 2010 Transmission Plan stakeholder process. [173] A representative from Z Global –WGD's consultants – participated in the February 16, 2010 stakeholder meeting.[174]

WGD did not follow the established process for submitting comments to the ISO regarding the draft 2010 transmission plan. Instead of emailing its comments to the email address that the ISO had established for the receipt of those comments (and all other comments during the course of the 2010 Transmission Plan stakeholder initiative), WGD sent a letter to an ISO Vice-

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170 *See* http://www.caiso.com/2738/2738128a83260.pdf

171 *See* http://www.caiso.com/273a/273af592b0d0.pdf

172 *Id.* at Slide 90 (Attachment O).

173 *See, e.g.,* http://www.caiso.com/244e/244eedd13fd20.pdf http://ww.caiso.com/2377/23771012752cd0.pdf (Attachment P).

174 Attachment Q.

President and Director on March 2, 2010.[175] Twenty other stakeholders submitted comments on the draft 2010 transmission plan, and all of them emailed their comments to the email address that had been established by the ISO for the receipt of stakeholder comments. WGD did not follow that standard process.[176]

The process that the ISO established for receiving stakeholder comments in this initiative and other major stakeholder initiatives allows the ISO to efficiently monitor, track, and post all comments that have been submitted. For each stakeholder process, there is a designated person responsible for taking all of the comments that have been sent to the established email address applicable to the particular stakeholder initiative and posting them to the website. If stakeholders do not email comments to the email address that has been established for this purpose, then the person that is responsible for posting comments to the website will not know whether or not particular stakeholders have submitted comments.[177]

The ISO has established a formal, centralized process for the submission of comments in connection with stakeholder initiatives because it .is efficient for both stakeholders and the ISO and takes the “guesswork” out of the comment submission process. This process has been used effectively in numerous ISO stakeholder processes. In this particular instance, consistent with the ISO’s

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175 Attachment R.

176 *See* http://www.caiso.com/20a1/20a1dbe417300.html

177 Also, if a stakeholder does not follow the established process for submitting stakeholder comments in an ongoing initiative and only sends a letter to an ISO executive, the ISO does not know what the intent of the stakeholder is.

practice for other major stakeholder initiatives, the designated person responsible for posting to the web all stakeholder comments resulting from the February 16, 2010 stakeholder meeting, namely a transmission planning administrative assistant went to the email address where comments were supposed to be sent and posted all of the comments that were properly submitted to the ISO's website.

Because WGD did not follow the applicable process for submitting comments on the 2010 Transmission Plan stakeholder initiative – a process clearly set forth at the February 16 stakeholder meeting and repeated in the posted documents associated with the meeting – by submitting its comments to the appropriate email address, the designated person was unaware of and unable to post WGD's comments and, indeed, had no reason to be aware that WGD had even sent a letter to Senior Management. It is inappropriate for WGD to claim that the ISO violated its BPM regarding the posting of stakeholder comments in light of the fact that WGD was the only stakeholder that did not follow the clearly stated process for submitting comments, which would have allowed any WGD comments to be posted, consistent with the ISO's standard process.

The ISO notes that it has a separate process for handling letters – such as WGD's March 2, 2010 letter – sent to ISO executives and requiring a written response. Such letters are logged, and the Executive Assistants track the status of a response. Once the ISO responds to a letter, the matter is closed. Because WGD's letter was sent to a Vice-President, it was handled in this manner. Ms.

Mueller states in a conclusory manner that the ISO tariff requires the ISO to submit a response to all comments submitted during the transmission planning stakeholder process but she does not cite to any specific tariff provision that imposes such a requirement. Indeed, the ISO tariff does not impose such a requirement. Section 2.1.2.4 of the BPM for Transmission planning does require that the final transmission plan respond to comments received "throughout development of the transmission plan," but that cannot reasonably be understood to include a letter sent to ISO management outside the established transmission planning process channels and email address established for the receipt of stakeholder comments. As discussed above, because WGD did not follow the proper procedure for submitting stakeholder comments to the ISO and consequently the person responsible for posting comments to the website was unaware that WGD had even submitted comments in the stakeholder process. It is therefore not surprising, and not a violation of the BPM, that WGD's comments were not posted, and that the ISO did not discuss such comments in its matrix of responses to stakeholder comments.

Nonetheless, the ISO fully fulfilled its responsibility to be responsive to market participants. The ISO *did* respond to WGD's letter comments – by the same means as that by which they were delivered, i.e., via letter dated May 5, 2010. In fact, the ISO's response is included in the Complaint as Attachment S (and as Attachment S to the instant answer). The ISO also addressed many WGD arguments in the final 2010 Transmission Plan. WGD simply chooses to ignore the fact that its projects were either not needed, or were not the most cost-effective solutions to meeting identified reliability needs.

E. WGD's Allegations Regarding The Individual WGD Projects Lack Merit

The ISO's consideration of the WGD projects was consistent with the ISO Tariff. The projects that WGD proposed to build were reliability-driven projects. As explained above in Section II.A.1 of the Answer, under the unambiguous language of the Commission-approved ISO tariff, as recently affirmed by the Commission, WGD was not – and is not -- eligible to build reliability-driven projects. In addition, the ISO's treatment of the WGD project proposals was appropriate and consistent with the ISO tariff. The ISO's responses to WGD's allegations regarding the ISO's disposition of the WGD projects are set forth below.

1. Auburn 66 kV Energy Storage Project

Ms. Mueller states that WGD submitted a project to resolve the Category A thermal overload of the Placer 115/60 kV transformer and other thermal overloads, as identified by the ISO's September 17, 2009 Reliability Assessment.[178] She asserts, without providing any citation, that the ISO rejected the Auburn Energy Storage Project.[179] She claims that the ISO's rejection of the battery storage project is technically flawed for two reasons: (1) the ISO rejected the project prior to performing the necessary power flow

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178 Mueller Affidavit at ¶ 91.

179 *Id* at ¶ 82. All of WGD's request window submissions for the proposed projects that are the subject of this complaint are included in Attachment T hereto.

analysis to determine that the project could be a component of the long-term plan; and (2) the project was rejected prior to the ISO performing the necessary economic analysis to determine if the project was the least cost alternative.[180]

As an initial matter, Ms. Mueller's assertion that the ISO rejected the Auburn Energy Storage project as a possible solution to address reliability concerns in the area is incorrect. Indeed, at page 111 of the 2010 ISO Transmission Plan, the ISO expressly stated that "the ISO will evaluate the battery storage project to determine whether PG&E should be directed to install such facility to address reliability concerns in the area."[181] The ISO also stated that it would "consider [PG&E's] Auburn-Placer voltage upgrade and the Auburn battery storage project, along with other possible options in the next ISO planning cycle to determine what facilities PG&E should be required to construct to meet reliability needs in the area.[182] The fact that the projects had not been rejected was confirmed in the ISO's May 5, 2010 letter to Roger Feldman. In response to WGD's claim that the ISO rejected WGD's battery storage proposal, the ISO stated:

> As an initial matter, the ISO has not yet approved a project(s) to meet the myriad of reliability needs in this area. The ISO will continue to study viable options that can provide a comprehensive, long-term solution to these needs. Even if the ISO ultimately were to approve a storage battery as an element of that comprehensive

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180 *Id.* at ¶ 85.

181 *See* http://www.caiso.com/2771/2771e57239960.pdf Sections of the final 2010 Transmission Plan discussing the treatment of WGD's storage projects are included in Attachment U).

182 *Id.* As discussed above, under Section 24.1 of the ISO Tariff, PTOs with a PTO Service Territory in which the a proposed reliability transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, operate, and finance such needed upgrade.

> solution, WGD would not be able to own or maintain that facility under the terms of the ISO tariff.[183]

The ISO added:

> At this time, the ISO does not consider the battery project as a comprehensive long-term solution, however, the ISO will further assess the Atlantic - Placer Voltage Conversion project along with other possible options (including battery storage) in the next planning cycle. As indicated above, however, if the ISO were to find that a battery storage resource is needed, PG&E would be the entity to construct and own it under the ISO tariff. Thus, WGD's proposal is rejected to the extent that it contemplates that WGD would own, construct, finance and maintain any battery storage facility found to be needed.[184]

Thus, the ISO has not rejected a battery storage project as a possible solution to reliability concerns in the Placer area. However, under the express terms of the ISO tariff, WGD would not be able to construct, own, finance and maintain such reliability project that is designed to maintain reliability on PG&E's local transmission system that is 60 kV and 115 kV.

As the ISO indicated both in its 2010 Transmission Plan (page 111) and its May 5, 2010 letter to Roger Feldman[185], and as discussed in the attached Declaration of Catalin Micsa, the Placer area is very complex with both peak and off-peak transmission constraints. Accordingly, it requires a comprehensive long-term solution that solves all of the constraints, not a solution that addresses only a single constraint. The power flows in and through this area are driven not only by load levels, but also by hydro generation output and the Drum-Summit intertie flows. Due to these factors, the operation of this system is extremely dynamic

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183 *See* Attachment S at 11.

184 *Id.*

185 *Id.* at 12.

with multiple constraints that need to be mitigated throughout the day.[186] It is not clear, at this time, that that a battery storage resource can charge enough throughout the daily cycle in order to help mitigate the binding constraints in the area throughout the day.[187] Thus, this area is one of the worst areas on the ISO- Controlled Grid to add load even during off-peak hours.[188]

Although the ISO did not reject a battery storage solution and expressed its intent to study the project in developing a comprehensive solution for reliability problems in the area, the ISO noted that the battery storage project itself did not constitute a comprehensive long-term solution for the overall problems in the Placer area and the greater Atlantic-Placer area.[189] The ISO stressed that because the reliability needs in this area are interrelated, the ultimate solution or solutions need to complement each other and ensure full compliance with reliability standards.

Importantly, PG&E's proposed Auburn-Placer Voltage Conversion project solves significantly more identified reliability problems in the area compared to the Auburn Battery Storage Project. Based on the ISO's review, PG&E's Auburn-Placer Voltage Conversion project solves 15 peak reliability problems in the area, as well as other off-peak problems driven by hydro and import

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186 2010 Transmission Plan at 111 (Attachment U); May 5, 2010 Letter at 12. (Attachment S); Declaration of Catalin Micsa at ¶10___.

187 May 5, 2010 Letter, Complaint Attachment S at 12; Micsa Declaration at ¶11.

188 *Id.*

189 May 5, 2010 Letter at 12 Attachment S.

patterns.[190] On the other hand, WGD's Auburn storage project only addresses two reliability problem s (*see* overloaded facility "Placer 115/60 kV line" as set forth at page 88 in the 2010 Transmission Plan).[191] WGD's cost comparison of the Auburn Energy Storage Project and the Auburn-Placer Voltage Upgrade is thus not an "apples-to-apples" comparison of the two projects. Because WGD's analysis fails to account for the costs of the additional transmission projects that would be needed to solve the 13 reliability problems that the battery project does not solve based on the project description contained in WGD's request window submission form (but the Auburn-Placer Voltage Conversion project does), the costs associated with approval of the WGD project are substantially understated by comparison. In addition, WGD's cost comparison analysis is flawed for the reasons set forth in Neil Millar's Declaration and discussed herein. In any event, because that the ISO has not yet approved specific solutions for the myriad of reliability concerns in the Placer area, any cost comparisons for purposes of this complaint are premature and speculative.

2. WGD's Coppermine 70 kV Storage Project

Ms. Mueller states that WGD submitted the Coppermine Energy Storage Project to address the Category B thermal overload and voltage overloads in the Coppermine area.[192] In its Coppermine 70 kV battery storage request window

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190 Micsa Declaration at ¶10. *See also* pages 88-110,tables 3-3.4.6 through 3-3.4.9 in the 2010 ISO Transmission Plan, where the ISO preliminary solution is titled "Upgraded Atlantic Placer Corridor to 115 kV operation. There are three reliability problems listed on page 88, two on page 91, five on page 103, three on page 104, and two on page 108. *See* Attachment V.

191 Micsa Declaration at ¶10.

192 Mueller Affidavit at ¶ 86.

submission, WGD stated that PG&E's 2009 Electric Transmission Grid Expansion Plan identified that for summer peak conditions an outage of the Borden Coppermine 70 KV line, when Friant Dam generation is offline, will cause low voltages in the Coppermine 70 KV area. WGD proposed to install a battery storage device at the Coppermine 70 kV substation, followed by six additional battery storage installations (one every five years) to account for load growth.

The ISO's preliminary Reliability Assessment study results for the Greater Fresno Area in connection with the 2010 Transmission Plan process did not identity any overloads or voltage concerns resulting from the Category B contingency that WGD's Coppermine 70 kV storage project was intended to address, namely an outage of the Coppermine Borden 70 kV line when Friant Dam generation is offline. [193] As the ISO indicated at page 180 of the final 2010 Transmission Plan (Attachment U hereto) and in its May 5, 2010 letter to WGD, Attachment S hereto, the Category B low voltage problem and overloads identified by PG&E and the ISO in the 2009 plan were resolved by a previously completed maintenance project, the Coppermine-Tivy Valley-Reedley 70 kV reconductoring project.[194] Accordingly, the final reliability study results for the Greater Fresno Area, as reflected in the final 2010 Transmission Plan at pages 155-80, do not show any overloads associated with the Category B event relied on by WGD.

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193 Attachment W.

194 At paragraph 89 of Ms. Muelller's affidavit, she refers to the ISO's May 5, 2010, letter which indicated that there was no need for WGD's Coppermine 70 kV storage project because PG&E had undertaken the Coppermine-Tivy Valley-Reedley maintenance project, which the ISO had failed to model in the 2009 plan, and that maintenance project had reduced a Category B overload to Category D.

Ms. Mueller notes that the 2008 Transmission Plan identified the maintenance project in the study assumption list, and that the 2008 Transmission Plan is used as input for modeling the transmission system for the 2009 Transmission Plan. She raises the question of why the results of the 2009 Transmission Plan showed an overload even though if should have reflected the impact of the Coppermine- Tivy-Valley-Reedley maintenance project in the assumptions.

The Coppermine-Tivy Valley-Reedley maintenance project was completed on September 30, 2008,[195] approximately fourteen months before WGD submitted its project proposal in the transmission planning request window.[196] The ISO did not model the Coppermine-Tivy Valley-Reedley 70 kV maintenance project in its analysis for the final 2009 Transmission Plan because the base cases for the 2009 analysis were developed in April 2008, *i.e.,* before the maintenance project was completed.[197] This addresses the modeling issue raised by Ms. Mueller's affidavit regarding the reflection of an overload in the 2009 transmission plan.

However, the ISO did model the Coppermine-Tivy Valley-Reedley maintenance project in its analysis for the 2010 transmission planning process, and the ISO found no reliability problem, as discussed above.[198] Accordingly,

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195 Micsa Declaration at ¶14.

196 WGD submitted its proposed project on November 30, 2009. *See* WGD's proposed Coppermine Storage Project Request Window submission included in Attachment [T] hereto.

197 Attachment S ; Micsa Declaration at ¶14.

198 Micsa Declaration at ¶14.

there is no need for any new transmission project for the Category B event identified by WGD in its request window submission form. This is confirmed in the final study results for the Fresno area, as contained in the 2010 Transmission Plan.[199]

Ms. Mueller also states that the 2010 transmission planning process reliability results do not show an overload because of a new system configuration that shows the Coppermine-Tivy-Valley 70 kV line in the open position. She then states that under this new configuration, the loss of Borden-Coppermine while the Friant Dam is offline will result in all load being dropped in the Coppermine 70 kV load pocket and that this constitutes a Category B contingency.[200] Ms. Mueller asserts that the ISO failed to follow its Grid Planning Standards applicable to Category B events.[201] Finally, she objects to the fact that the procedure to open up the Coppermine-Tivy-Valley 70 kV line to allow load dropping was not submitted through the ISO's transmission planning process request window, and claims that the ISO violated the transmission planning process by allowing system configuration changes outside of the transmission planning process.[202]

Ms. Mueller is incorrect. As indicated in the attached Declaration of Catalin Micsa, Mr. Micsa downloaded the information available to stakeholders for the planning year 2014 – which is the base case specifically studied by the

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199 *See* Attachment X hereto.

200 Mueller Affidavit at ¶¶ 91-92.

201 *Id.* at ¶ 92.

202 *Id.* at ¶¶ 93-94.

ISO in the 2010 Reliability Assessment – and the diagram attached hereto shows that the breaker on the Coppermine-Tivy Valley line is not open for purposes of the ISO's reliability study,[203] contrary to Ms. Mueller's claim. It should be noted that the 2010 base case, which is also posted, does show the breaker as being open, reflecting past *operating* practices. However, the breaker should be closed as reflected in the ISO's Reliability Analysis -- and the ISO studied the line with the breaker closed in its 2010 Reliability Assessment studies because the Coppermine-Tivy Valley-Reedley maintenance project resolved past overload concerns. If there is any need to open the breaker in future years it would be solely for operating conditions beyond the planning assumptions, but it should not be open for planning purposes; nor did the ISO study it in the open position. Thus, the ISO has not "planned" for any load shedding in response to Category B events, all reliability performance concerns were resolved by the maintenance project, and there are no identified overloads for planning purposes.

Thus, Ms. Mueller's erroneous claim that the ISO has "planned" the loss of the Borden-Coppermine 70 kV line when Friant Dam generation is offline and that this loss will result in load shedding is simply incorrect. Accordingly, Ms. Mueller's claim that the ISO failed to follow the applicable Grid Planning Standards for Category B events fails, among other reasons, because her fundamental premise, *i.e.,* that the ISO will be shedding load if the claimed Category B event occurs in the Coppermine area, is incorrect.

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203 *See* Attachment Y to this Answer.

For similar reasons, Ms. Mueller's claim that the ISO was remiss because the purported procedure to open up the Coppermine-Tivy Valley 70 kV line to allow load shedding was not submitted through the transmission planning process request window is misplaced. As discussed above, the ISO did not study or "plan" the system with the breaker open during the 2010 transmission planning cycle; it studied and "planned" the system with the breaker closed because the aforementioned Coppermine-Tivy Valley-Reedley maintenance project solved all identified overloads in the area. Thus, the ISO has not planned to shed load if the identified Category B contingency occurs.

Even assuming *arguendo* that the ISO was relying on an operating procedure in the planning process, operating procedures to address reliability concerns are not submitted through the ISO's transmission planning request window; only reliability related transmission upgrades and additions are required to be submitted through the request window. An operating procedure is neither. *See* Section 24.2.3 of the ISO tariff in effect during the relevant period.

Ms. Mueller's claim that the ISO violated the transmission planning process by allowing system configuration changes outside of the transmission planning process is likewise misplaced. First, no system reconfiguration has taken place for planning purposes. The ISO studied the Coppermine-Tivy Valley line with the breaker closed as discussed above. Moreover, Complainants do not -- and cannot -- cite to a single tariff provision to support the claim that the ISO violated the approved terms and conditions of the ISO transmission planning process. System reconfigurations, reliability-based operating procedures, maintenance projects, remedial action schemes, and similar activities routinely occur on all electric systems, often on a daily basis, in order to enable the system operator to operate the system in a reliable manner. There is no requirement that the ISO or transmission owners undertake these activities only within the confines of the transmission planning process.

Section 24.2.3 of the ISO tariff in effect during the relevant period governs request window requirements, and nothing in that or any other provisions of the ISO tariff requires maintenance projects, reliability-related operating procedures, special protection schemes, and similar mechanisms to be submitted through the transmission planning request window. Rather, the request window provisions of the ISO tariff only require that reliability-driven transmission upgrades and additions (or demand response/generation alternatives to such transmission projects) will be submitted through the request window. Further, the ISO tariff only contemplates that the ISO will approve capital projects -- transmission upgrades and additions. *See* ISO tariff sections 24.1 and 24.2.4(d). Even if there were a procedure to open a breaker, such a procedure would be neither a transmission upgrade nor an addition, and would not be subject to approval in the ISO transmission planning process. The ISO's conclusions are further supported by other provisions of the ISO tariff and Transmission Control Agreement ("TCA"). The TCA sets forth the obligations of the ISO and PTOs. Section 4.3 of the TCA, which sets forth the rights and responsibilities of PTOs, provides that each PTO shall retain its benefits of ownership and its rights and responsibilities in relation to the transmission lines and associated facilities placed under the ISO's operational control, except as provided under the TCA. Further, the PTOs are responsible for operating and maintaining those lines and facilities in accordance with the TCA, Applicable Reliability Criteria, Operating Procedures, other criteria, and ISO Protocols. Rights and responsibilities that have not been transferred to the ISO as operating obligations under Section 4.1.1 of the TCA remain with the PTO. In particular, Section 6.1 of the TCA provides that each PTO shall have the exclusive right and responsibility to operate and maintain its transmission facilities and associated switch gear and auxiliary equipment. Under Section 6.1.1 of the TCA, each PTO is responsible for inspecting, maintaining, repairing, replacing, and maintaining the rating and technical performance of its facilities under the ISO's operational control in accordance with Applicable Reliability Criteria.

Maintenance projects, such as the Coppermine-Tivy Valley maintenance project are undertaken in accordance with Section 9 of the ISO tariff and Sections 7 and 14 of the TCA; they are not undertaken through the transmission planning process.[204] The ISO also notes that Section 8.1.1 of the TCA, applicable to critical protection schemes that support ISO controlled grid operations, provides that:

> Each Participating TO shall maintain the design, functionality, and settings of its existing RAS [remedial action scheme], UFLS [under frequency load shedding] and UVLS [under voltage load shedding] schemes. New or existing schemes that are functionally modified must be in accordance with WSCC [now WECC]/NERC planning, reliability, and protection policies and standards. Each Participating

[204] Appendix C of the TCA sets forth the standards for the maintenance, inspection, repair, and replacement of transmission facilities under the ISO's operational control.

> TO shall notify the ISO in advance of all RAS, UFLS and UVLS schemes functionality and setting changes that affect transmission facilities on the ISO Controlled Grid. Each Participating TO shall not disable or take clearances on RAS or UVLS schemes without the approval of the ISO through the Maintenance Outage and Forced Outage coordination process in accordance with the ISO tariff. Clearances on UFLS may be taken without approval depending on the armed load disabled as agreed to between the Participating TO and ISO and incorporated in the Operating Procedures.

Section 8.2 of the TCA further provides that each PTO shall provide to the ISO protective relay system functional information necessary to perform planning and operating analysis, and to operate transmission facilities on the ISO controlled grid in accordance with WSCC [now WECC]/NERC planning, reliability and protection policies and standards. Thus, PG&E is responsible for the types of activities that it has undertaken in the Coppermine area under the express terms of the Commission-approved TCA, and there is no requirement in either the TCA or the tariff that such activities be submitted through the transmission planning process request window and be approved through the transmission planning process. The TCA clearly contemplates that a PTO can undertake such activities provided it acts in accordance with the TCA and follows any applicable tariff provisions under Section 9 pertaining to maintenance outages.

In summary, there are no tariff violations with respect to the ISO's rejection of WGD's proposed Coppermine 70 kV storage project. There is no reliability need in the area and, as such, there is no need for any reliability project, including WGD's proposed storage project. WGD essentially is proposing to impose approximately $ 54 million in additional costs (based on the

NPV of the WGD project's yearly revenue requirement) [205]on ratepayers for a project that is not needed to maintain reliability.[206]

3. Weedpatch 70 kV Energy Storage Project

Ms. Mueller notes that WGD proposed the Weedpatch Storage project to address a Category B thermal overload identified by the ISO in the September 15, 2009, Reliability Assessment results for the 2010 Transmission Plan.[207] Specifically, in its request window submission form for the Weedpatch Storage project (contained in Attachment T hereto), WGD stated at pages 2 and 6 that "[t]he CAISO Reliability Assessment Results (September 15, 2009) for the Kern area identified that loss of the Wheeler-Weedpatch 70 kV line while Kern Canyon generation is offline will cause an emergency overload on the line between San Bernard and Stalin Jct. 70 kV." WGD added that the ISO's studies indicated "that the overload will reach 100% of its emergency rating by 2014." *Id.*

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205 Alaywan Affidavit at ¶ 61.

206 In his affidavit, Mr. Alaywan claims that the NPV of WGD's storage project is lower than the NPV of PGE's transmission project's yearly revenue requirement. Alaywan Affidavit at ¶¶ 61-63. It is unclear to which project Mr. Alaywan is referring. At page 11 of Attachment A to his Affidavit, he references a Borden-Coppermine 70 kV Upgrade. It is not clear what project this is or where the information regarding such project came from. The ISO is not aware of any Borden-Coppermine 70 kV Upgrade. The ISO did not approve a PG&E transmission project to address a Coppermine reliability need in the 2010 Transmission Plan because no such need was identified in the ISO's applicable reliability assessment, and PG&E did not submit a transmission project in the 2009-2010 planning cycle to address to address this "non-existent" need. As the ISO indicated above, the identified reliability problem was resolved through a completed maintenance project. It is impossible for the ISO to properly evaluate Mr. Alaywan's cost comparison analysis given that he is not transparent as to which specific proposed PG&E transmission upgrade(s) or addition(s) he used for cost comparison purposes. PG&E has previously submitted transmission projects in this general area which the ISO did not approve and did not find to be needed. Any of these transmission project proposals which were not approved by the ISO would not be appropriate for a cost comparison purporting to compare a project proposal to the ISO's approved transmission plans..

207 Mueller Affidavit at ¶ 96.

Ms. Mueller states that an operating procedure relied upon by the ISO to open the Weedpatch CB 42 breaker during the Summer months essentially de-loops an otherwise integrated system and places the sub-stations on a less reliable radial configuration. She appears to believes that this results in the ISO dropping load in response to the Category B event identified in WGD's request window submission and argues that this is an acceptable alternative in lieu of building transmission under the ISO planning standards only if the ISO first obtains Board approval to implement a load shedding scheme and provides a notification period to stakeholders with an opportunity to respond.[208]

The ISO notes that opening the breaker shifts the load to a radial configuration during the summer months. [209]The ISO also notes that in its written comments sent to ISO management on March 2, 2010 regarding the ISO's proposed recommendations and treatment of the WGD projects (Attachment R to this Answer), WGD never raised this argument. The draft 2010 transmission plan (Attachment AA]to this Answer at page 190) and the final 2010 transmission plan (Attachment U])to this Answer at pages 188-89), as well as the ISO's February 16, 2010 stakeholder presentation (*see* Attachment BB) to this Answer) all mentioned the procedure to open the Weedpatch CB42 breaker to prevent overloads on the line and indicated that, as a result, the ISO was rejecting WGD's proposed storage project that was intended to address the same emergency reliability performance problem that opening the breaker

208 Mueller Affidavit at ¶ 100.

209 Micsa Declaration at ¶ 17.

resolves. The final transmission plan which expressly stated that the ISO was rejecting WGD's project and instead relying on a procedure to open the Weedpatch CB 42 breaker was provided to the Board, and the plan was discussed in a presentation at the Board meeting. The Board had an opportunity to reject the ISO's recommendation but did not.

As discussed *supra,* the ISO's process and procedures for receiving and evaluating project proposals and alternatives, and for receiving input during the transmission planning process, has been radically re-vamped as a result of Commission approval of the ISO's Order No. 890 compliance filing (and now Commission approval of the revised planning process in Docket No, ER10-1401) As discussed herein, the ISO was fully transparent in its draft transmission, in its presentation to stakeholders, and in the final 2010 Transmission Plan that the ISO was relying on an operating procedure to open the breaker and rejecting WGD's proposal to address the identified reliability need. Because the ISO's Board meetings are public and provide for public comment, WGD would have had every opportunity to come before the Board and argue that its storage project should be approved instead of the ISO relying on the opening of the breaker. It did not avail itself of that opportunity.[210]

The ISO also notes that WGD has not established the basic pre-condition for a reliability performance violation, *i.e.,* that there be an identified Category B overload of a line from which the transmission operator cannot recover. By its

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210 *See* ISO tariff sections 24.1and section 4.3.1 of the transmission planning BPM in effect during the relevant period. The ISO notes that under the express terms of the ISO tariff that the Commission approved in the Order No. 890 compliance process, the only items that the ISO Board approves as part of the planning process are transmission upgrade and addition projects that have a capital cost of $50 million or more

own admission in its request window submission for the Weedpatch Storage project, and the ISO's study results, there is no Category B overload in 2014 on San Bernard-Stalin Jct. as identified by WGD. WGD acknowledges in its request window submission form that loading is at 100 percent in 2014. The ISO's initial technical study with the breaker closed showed this result and a 1% overload in 2019.[211] With the breaker open, there is no overload in either year in response to the Category B event identified by WGD in its request window submission form. Thus, WGD has not demonstrated that there is a need for a reliability project beginning in March 2014, which is the in-service date that WGD proposed in its request window submission for the Weedpatch storage project. The ISO will monitor the loading of this line to assess whether a project is ultimately needed, but notes that this is an area of the grid where there is minimal, if any, load growth.[212]

Ms. Mueller asserts that opening the breaker during the summer months essentially de-loops an otherwise interconnected transmission system and places the substations in a less reliable radial configuration.[213] There is no evidence that this procedure creates a reliability need which should be addressed in the ISO transmission planning process. The ISO notes that this procedure was most recently used during the summer of 2009, and there were no reliability problems. The ISO's final study results for the Kern local area are

211 Micsa Declaration at ¶ 19

212 Micsa Declaration at ¶19.

213 Mueller Affidavit at ¶ 97.

reflected at pages 181-189 of the final 2010 Transmission Plan, and they do not identify any Category B overload on this line.[214]

Ms. Mueller also claims that the ISO updated the uniform planning assumptions used for the 2010 plan by incorporating the opening of Weedpatch CB 42 and that "it should not be the ISO's practice to allow PG&E to arbitrarily change system configurations to avoid the need for independent transmission projects."[215] She also objects to the fact that the procedure to open Weedpatch CB 42 was not submitted through the ISO's transmission planning process request window, and claims that it should not be the ISO's practice to allow arbitrary changes to system configuration outside of the transmission planning process as an attempt to reject proposed independent transmission.[216]

With respect to Ms. Mueller's claim that PG&E should not be permitted to arbitrarily change system configurations, the ISO notes that the operating procedure to open the Weedpatch CB 42 breaker during the summer months is an existing procedure that was most recently used during the summer months of 2009 -- *well before WGD's Weedpatch storage project was ever submitted in the request window on November 30, 2009.*[217] Thus, there is no basis whatsoever to claim that this procedure was implemented for the purpose of preventing WGD or

214 Attachment Z to this Answer.

215 Mueller Affidavit at ¶ 99.

216 *Id.* at ¶ 101.

217 WGD's Weedpatch Storage Project was submitted into the request window on November 30, 2009. *See* Weedpatch Storage Project Request Window Submission included herein in Attachment [T].

any other independent transmission provider from building a transmission project.[218]

For the same reasons explained in the discussion above with regard to the Coppermine project, there is no requirement in the ISO tariff that PG&E's operating procedure to open the breaker be submitted through the ISO's transmission planning request window or that it be approved through the transmission planning process. [219]

With respect to Ms. Mueller's claim that the ISO changed assumptions during the planning process, the ISO notes that on October 26-27 , 2010 it held a meeting with stakeholders to discuss , *inter alia,* the September 15 Reliability Assessment results and to obtain input from stakeholders. In its draft Transmission Plan posted in February 2010, the ISO documented that the

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218 In any event, there would be no reason for the ISO or PG&E to engage in such an arbitrary action because under the ISO tariff, only PTOs with a PTO Service Territory are permitted to build, own, finance, and maintain reliability projects. As explained above, under the ISO tariff, WGD is ineligible to be designated as the Project Sponsor to build the proposed reliability solution.

219 The ISO notes that there is no defined term -- system re-configurations -- in the Tariff. However, the ISO Tariff defines Special Protection System (SPS) as

> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of the faulted components to maintain System Reliability. Such actions may include changes in Demand, Generation (MW or MVar), or *system configuration* to maintain system stability, acceptable voltage or power flows. An SPS does *not* include (a) Underfrequency Load Shedding or under Voltage Load Shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of an SPS). An SPS is sometimes referred to as a Remedial Action Scheme. (emphasis added).

Thus, the ISO tariff contemplates that changes in system configuration are not transmission upgrades and additions and are not required to be submitted in the transmission planning process. As discussed above, SPS development and similar activities are the responsibility of the PTO, and SPSs are not submitted into or processed through the transmission planning process. As indicated above, the tariff does not require SPS schemes, operating procedures, and maintenance projects, etc., to be submitted through the request window.

September 15 Reliability Assessment results showing overloads in the Weedpatch area were flawed due to incorrect modeling information that was provided by PG&E.[220] The ISO noted that it would revise the study results and reflect them in the 2010 Transmission Plan and final study results. Specifically, the ISO stated that the operating procedure to open the Weedpatch CB 42 addressed the Weedpatch area overloads.[221] The ISO also discussed its flawed assumptions at a February 16, 2010 stakeholder meeting and noted in its posted presentation that, as a result of the existing operating procedure, there was no need for a reliability upgrade or addition and, accordingly, the ISO was rejecting WGD's Weedpatch storage project.[222] In the Final 2010 Transmission Plan, which reflects the final reliability study results, the ISO noted the incorrect modeling information and corrected the study results to reflect the procedure to open the Weedpatch CB 42.[223] As a result, there was no need for any reliability upgrade or addition, and it was rejecting the Weedpatch Storage Project. Thus, the ISO fully complied with the then-effective section 24.2.2.1 (b) of the ISO tariff, which enables the ISO to change or deviate from operating assumptions as long as it documents that it has done so. As discussed above, the ISO did document its actions.

In summary, there are no tariff violations with respect to the rejection of WGD's proposed Weedpatch 70 kV storage project. There is no reliability need

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220 See the ISO's draft 2010 Transmission Plan, provided as Attachment [AA] to this Answer.

221 *Id.*

222 *See* Attachment BB at slide 60.

223 *See* Attachment T]at pp. 188-89.

in the area and, as such, there is no need for any reliability project, including WGD's proposed storage project. WGD essentially is proposing to impose approximately $ 19.82 million in additional costs (based on the NPV of the WGD project's yearly revenue requirement)[224] on ratepayers for a transmission project that is not needed to maintain reliability.[225]

4. Potrero 115 kV Energy Storage Project

Ms. Mueller states that WGD proposed the Potrero Energy Storage Project to address the ISO's 2010 Local Capacity Technical Analysis Final Report and Study results, which indicated that after the TransBay Cable and Martin-Bayshore-Potrero re-cable are operational, the local capacity requirement would be 25 MW in 2010, 15 MW by 2011, and 10 MW in 2013.[226] Indeed, in its November 30, 2009, request window submission for the Potrero 115 kV storage project, WGD stated that its 20 MW battery storage unit was needed in 2011 "to supply San Francisco with the needed capacity and energy" and to "displace" 10

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224 *See* Alaywan Affidavit at ¶ 61.

225 In his affidavit, Mr. Alaywan claims that the NPV of WGD's storage project is lower than the NPV of PGE's transmission project's yearly revenue requirement. Alaywan Affidavit at ¶¶ 61-63. It unclear which PG&E project Mr. Alaywan is referring to. At page 19 of Attachment A to his Affidavit, he simply references "Alternative" as the "straw man" he has established for purposes of comparing to Weedpatch storage project, and he assigns a $12 million capital cost to that "Alternative" without providing any indication of what exactly the "Alternative is or what is the basis for the cost number. It is not clear what project this is or from where the information regarding such project came. The ISO is not aware of any PG&E project to address the claimed Weedpatch reliability concern or what the components of any such project would be. The ISO did not approve a PG&E transmission project to address the Weedpatch reliability concern identified in the 2010 Transmission Plan, and PG&E did not even submit a transmission project in the 2009-2010 planning cycle to address this specific concern. As the ISO indicated above, the identified reliability concern was resolved through a procedure to open the breaker to allow the load to be served off of a radial line if a Category B event were to occur. Opening a breaker is not a $12 million capital project. It is impossible for the ISO to properly evaluate Mr. Alaywan's cost comparison analysis without basic information as to which proposed PG&E transmission upgrade(s) or addition(s) he used for cost comparison purposes..

226 Mueller Affidavit at ¶ 102.

MW of local capacity to account for load growth and the closing of Potrero generation.[227]

Ms. Mueller claims that the ISO's stated reasons for finding that there was no need for the Potrero Storage project were a significant reduction in load forecast for San Francisco and the planned completion of the Martin-Bayshore Potrero cables.[228] She notes that in its May 5, 2010 letter to WGD, the ISO indicated that PG&E had provided updated line ratings which were approximately 30% higher than what was previously estimated and, as a result, there were no overloaded facilities. Ms. Mueller alleges that the ISO allowed the unified planning assumptions to be updated by incorporating the updated line ratings and load forecasts in order to eliminate the need for WGD's Project.[229] She asserts, without any evidence, that it should not be the ISO's practice to allow PG&E arbitrarily to change the line ratings after the fact to avoid the need for an independent transmission project. Ms. Mueller further asserts that the ISO violated the transmission planning process by arbitrarily changing the unified planning assumptions in order to eliminate the need for WGD's project.[230] Finally, Ms. Mueller argues that the ISO adopted a new system configuration that would drop load in lieu of building transmission, and the ISO did not provide

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227 *See* WGD's Potrero 115 kV Storage Project Request Window submission at 2, 6-7 included in Attachment T hereto.

228 Mueller Affidavit at ¶ 103.

229 *Id.* at ¶ 106.

230 *Id.*

stakeholders with notice of this approach or obtain Board approval as required by the ISO's Grid Planning Standards.[231]

As an initial matter, the ISO notes that WGD's position regarding the need for their project is based on the ISO's 2010 Local Capacity Technical Analysis Final Report (also known as the "LCR technical study"), which identified, among other things, the minimum amount of existing resources that need to be procured in the San Francisco local area and established the basis for the ISO's potential procurement of backstop generation resources. WGD's position is not based on the results of the ISO's Reliability Assessment for the 2010 Transmission Plan, which is the technical study that the ISO performs to comply with applicable NERC planning standards and identify transmission facilities that do not meet reliability performance requirements during the planning horizons being studied.[232] The ISO determines what solutions are needed to resolve reliability contingencies based on the needs identified in the Reliability Assessment.[233] The ISO conducts the LCR technical study to comply with resource adequacy requirements as set forth in Section 40.3.1 of the ISO Tariff. The LCR technical study serves three basic purposes: (1) it identifies the minimum quantity of existing local resources that must be procured in order to comply with Section 40.3 of the ISO tariff applicable to Resource Adequacy requirements, titled *Local Capacity Area Resource Requirements Applicable to Scheduling Coordinators for All Load Serving Entities*; (2) it provides a basis for allocating to load serving

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231 *Id.* at ¶ 107.

232 *See* 2010 Transmission Plan at 6 (Attachment CC to this Answer).

233 *Id.;see also* Micsa Declaration at ¶21.

entities their next year's local capacity requirements; and (3) it establishes the basis for potential local capacity procurement by the ISO under the terms of the Interim Capacity Procurement Program should LSE procurement of generation capacity be deemed insufficient.[234] The LCR technical study is not a reliability study and is not used for the purpose of identifying thermal overloads and voltage problems in order to comply with NERC planning criteria.

Further, it is disingenuous for WGD to claim that their proposed storage battery can be used to provide San Francisco with energy and capacity. As discussed in greater detail *infra,* the storage unit is only permitted to function as a transmission asset; it is not permitted to function as a generation resource. Accordingly, the storage battery can only be used at those times when the ISO determines that there is a reliability need, such as a voltage problem or a thermal overload, that need that can be addressed by operating the battery. WGD's own filings with the Commission and the applicable Commission orders provide that this storage unit will not -- and cannot -- provide Energy, Ancillary Services and capacity, which are services provided by generators and resource adequacy resources. *See* discussion in section F.3 *infra*. Thus, WGD's battery storage unit is not a resource that could be procured by load serving entities under their resource adequacy procurement or by the ISO under its Interim Procurement Mechanism to satisfy local capacity resource requirements.

In any event, there simply is no reliability need for WGD's Potrero 115 kV storage project or any other reliability project in San Francisco. The local

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[234] 2010 Transmission Plan at 7-8 (Attachment DD to this Answer); *see also* Micsa Declaration at ¶ 21.

capacity need referenced by WGD was based on PG&E's initial estimate of the ratings of Martin-Bayshore-Potrero cables #1 and #2 following recabling.[235] However, in August 2009, PG&E provided updated ratings that were approximately 30% higher than its earlier estimate. The ISO reviewed those updated ratings and found them to be reasonable.[236] As reflected in the ISO register where line ratings are maintained, the final ratings for the lines under normal conditions are the same as those submitted by PG&E in August 2009, and for emergency conditions, the actual ratings are 30 MVA higher than the updated ratings submitted in August 2009.[237] The draft Transmission Plan used those updated ratings and, when the revised ratings were applied, the ISO found there were no overloaded facilities that required generation at Potrero to mitigate.[238] Stakeholders, including WGD, were given the opportunity to submit comments on all elements of the draft transmission plan. Also, at its February 16, 2010 stakeholder meeting, the ISO's presentation on the San Francisco results (1) included a discussion of the updated line ratings and how that obviated the need for any new transmission upgrade or addition in the area.[239], and (2) listed this conclusion as a bullet in the Key Findings section. Stakeholders, including WGD, had an opportunity to comment on the ISO's conclusions. The final 2010 Transmission Plan and study results posted on March 9, 2010 include San

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235 May 5, 2010 letter to WGD at 13 (Attachment S).;Micsa Declaration at ¶22.

236 Micsa Declaration at ¶22.

237 *Id.*

238 *See* Attachment[EEto this Answer; including the ISO's draft Transmission Plan and 2010 Draft Transmission Plan (With Inclusion of San Francisco write-up).

239 *See* Attachment FF to this Answer.

Francisco study results and clearly state that, as a result of the recabling of the Martin-Bayshore-Potrero line, which significantly increased the ratings of such lines, there are no identified overloads.[240]Accordingly, the ISO rejected the Potrero Energy Storage Project and two PG&E proposed transmission upgrades -- the 115 kV Series Reactor Project and the Embarcadero-Potrero 230 kV project -- as not being needed. The ISO also found that no additional generation was needed in the city.

Ms. Mueller's claim that the ISO violated its transmission planning process by changing planning assumptions is incorrect. The transmission planning request window provisions under the then-effective section 24. 2.3 of the ISO tariff do not require re-rates to be submitted through the transmission planning request window. Re-rates are not transmission upgrades and additions that are approved by the ISO Board or ISO management in the planning process.[241]

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240 2010 Transmission Plan at 153-54; 276 (Attachment [U] to this Answer).

241 *See* Sections 24.1 and 24.2.4(d) of the ISO tariff. The ISO notes that, in accordance with Section 4.2. of the TCA, the ISO maintains a register of all transmission lines and associated facilities turned over to the ISO's operational control. This information includes applicable line ratings. Under Section 4.2.3 of the TCA, each PTO is responsible for

> submit[ting] an ISO Register change for each addition or removal of a transmission facility line or associated facility or Entitlement from the ISO's Operational Control or any change in a transmission line or associated facility's ownership, rating or the identity of the responsible Participating TO. The ISO shall review each ISO register change for accuracy and to ensure that all requirements of the [TCA] have been met. If the ISO determines that a submitted ISO register change is accurate and meets all the requirements of [the TCA], the ISO will modify the ISO Register to incorporate such change by the end of the next Business Day.

Changing a line's rating is an event contemplated by the TCA, and the PTO is the party responsible for any line rating changes and is obligated to notify the ISO of such changes. Importantly, WGD did not raise any issues with the level of the updated line ratings during the stakeholder process even though it had several opportunities to do so. Similarly, in its complaint WGD does not raise any objections regarding the line's updated rating or offer any evidence that

Section 24.2.2.1 (b) of the ISO tariff expressly contemplates that the ISO may deviate or modify the planning assumptions as long as it documents them in the study results. The tariff also contemplates that the ISO will consider the input it receives from stakeholders in completing its technical studies and posting the final study results. The ISO received input from PG&E regarding the updated line ratings and found them to be reasonable. As indicated above, the draft 2010 Transmission Plan, the ISO's presentation at the February 16, 2010 stakeholder meeting, and the draft Transmission Plan (With San Francisco results) all reflected and documented the fact that there were updated line ratings associated with the Martin-Bayshore-Potrero recabling. The final 2010 Transmission Plan, which reflects the final study results of the planning cycle together with the ISO's proposed solutions, also documented the ISO's reliance on updated line ratings. Based on these updated line ratings, there were no emergency overloads that needed to be addressed by a new transmission project or generation. The ISO notes that the updated line ratings were sufficient by themselves to address any overload concerns either under the original forecast or under the Uniform Planning Assumptions which included the reduced load forecast that the ISO used in its final study results. As such, the ISO did not need to rely on a reduced load forecast for San Francisco as the basis for rejecting both the Potrero storage project and PG&E's competing

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the updated line rating is inappropriate or unjustified. As such, the Commission should not countenance WGD's claim that updating the line rating was somehow inappropriate.

Embarcadero 230 kV project.[242] That is why the final 2010 Transmission Plan indicated that the recabling addressed all reliability needs.[243]

WGD's argument that the ISO arbitrarily allowed PG&E to change the line ratings after the fact to avoid the need for an independent transmission project is likewise misplaced. As a result of PG&E's re-rating of the Martin-Bayshore-Potrero lines, the ISO rejected PG&E's Embarcadero-Potrero 230 kV cable project as not being needed for reliability purposes. *See* 2010 ISO Transmission Plan at 153. That PG&E project was an alternative to WGD's storage project to resolve the identified reliability need in San Francisco. Thus, PG&E's re-rating not only eliminated the need for WGD's project, it also eliminated the need for PG&E's project. That hardly constitutes arbitrarily re-rating a line for the purpose of avoiding the need for an independent transmission project. Also, PG&E advised the ISO of the updated line ratings in August 2009 -- several months before WGD even submitted its Potrero storage project in the request window. The Complaint's unsupported allegation that the ISO arbitrarily permitted PG&E to update the rating should not be countenanced by the Commission. As indicated in the final transmission plan the ISO reviewed the re-rating, and found that it was acceptable. The recabled lines have become operational, and they

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242 Micsa Declaration at ¶23.

243 Even assuming *arguendo* that the ISO needed to rely on a reduced load forecast (in addition to the updated cable ratings) as the basis for rejecting the Potrero storage project and PG&E's Embarcadero 230 kV project, the ISO documented its use of a lower load forecast in the final study results and, as such, the ISO complied with Section 24.2.2.1 of the Tariff. In that regard, the draft Transmission Plan (p.155), the February 16, 2010 stakeholder presentation (Attachment FF), the draft Transmission Plan(with San Francisco results at pages 158, 168, 293-302, and the final Transmission Plan which reflects the final reliability study results (pp. 153-54, 276-83) all documented the use of a lower forecast consistent with section 24.2.2.1(d) of the ISO tariff.

have functioned successfully at their updated ratings without any resulting reliability problems.[244] Further, by a letter dated December 21, 2010, the ISO released the Potrero generation from their Reliability Must Run contract.[245] This paves the way for the closure of the Potrero units. Obviously, the ISO would not have agreed to this if it believed that reliability problems remained in San Francisco, the updated line ratings were insufficient to address reliability concerns, or that another reliability project was needed before the units could be shut down. Thus, the Complaint's allegation that the ISO arbitrarily allowed the re-rate lacks any factual basis. Ms. Mueller also alleges that the ISO did not provide a stakeholder notification period or receive Board approval for a system configuration that would drop load in lieu of building transmission.[246] This appears to be a boilerplate argument that has been included in the Complaint's arguments with respect to each individual project. First, no system re-configurations are involved here, and Ms. Mueller's affidavit makes no attempt to even identify what such system re-configuration is. Second, no load shedding for Category B contingencies is involved here because the updated line ratings eliminated any such potential overloads.[247] The final study results reflected in the in the 2010Transmission Plan show there are no facilities that are overloaded

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244 Micsa Declaration at ¶22.

245 *See* Attachment GG to this Answer.

246 *See* Mueller Affidavit at ¶ 107.

247 Micsa Declaration at ¶24.

due to Category B contingencies, and Category B and C voltages are satisfactory.[248]

In summary, there are no tariff violations with respect to the ISO's rejection of WGD's proposed Potrero storage project. There is no reliability need in the area and, as such, there is no need for any reliability project, including WGD's proposed storage project and PG&E's alternative proposed project. WGD essentially is proposing to impose approximately $ 48.57 million in additional costs on ratepayers (based on the NPV of the WGD project's yearly revenue requirement) [249]for a transmission project that is not needed.

5. WGD's Madison 115 kV Energy Storage Project

Ms. Mueller states that WGD submitted the Madison Energy Storage project to address category B thermal overloads in the Madison Area, as outlined in the ISO's Reliability Assessment Results.[250] She is incorrect. A review of WGD's Madison 115 kV storage project request window submission form (page 2) indicates that WGD submitted the project because "[t]he CASO Reliability

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248 2010 Transmission Plan at 279-84 (Attachment U). To the extent there are any Category C overloads on a few low voltage lines, Section II.4.B of the ISO's Grid Planning Standards provides that "[i]nvoluntary load interruptions are an acceptable consequence in planning for ISO Planning Standard C and D disturbances (multiple contingencies with the exception of the combined outage of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly cost effective (after considering all the costs and benefits." In other words, load shedding is permissible for Category C contingencies without Board approval; Board approval is needed only if the ISO desires to approve a capital project to address the contingency rather than rely on load shedding. WGD's request window submission form pertained solely to addressing LCR needs and failed to demonstrate -- and did not propose to demonstrate -- that its project would resolve any of the residual Category C overloads that might remain on the small number of 115 kV cables and 115/12/kV transformers. Indeed, WGD's request window submission form indicated that its project was intended to address purported LCR needs, not NERC reliability performance problems identified in the ISO's Reliability Assessment.

249 Alaywan Affidavit at ¶¶ 61-63. .

250 Mueller Affidavit at ¶ 108.

Assessment Results (September 15, 2009) for the Central Valley area identified that the Madison-Vaca 115 line will reach 100.1% of its normal rating by 2014. This is confirmed by the ISO's Reliability Assessment (page 25) which shows that this is a Category A overload with a 1% overload in 2014 and a 4% overload in 2019. Attachment HH hereto. Thus, Ms. Mueller mischaracterizes the intent of WGD's request window submission.

Ms. Mueller notes that the ISO found that the there was no need for WGD's storage project or any other transmission upgrade because the Vaca-Madison 115 kV line could be re-rated. [251] She also notes that in its May 5, 2010 letter to WGD, the ISO indicated that (1) the cost of a re-rate was minimal, (2) because the line was re-rated there was no overload concern, and (3) it could defer transmission for more than a decade. Ms. Mueller alleges that the ISO allowed its unified planning assumptions to be updated by incorporating updated line ratings in order to eliminate the need for WGD's project. She states that it should not be the ISO's practice to allow PG&E to arbitrarily change line ratings to avoid the need for independent transmission. [252]

As the ISO indicated in its May 5, 2010 letter to WGD, the cost of a rerate is often minimal, usually less than $100,000 for a facility like this.[253] On the other hand, WGD estimated the initial capital cost of their proposed battery to be $4.5 million for a 3 MW battery, with additional capital costs to be incurred as the additional battery capacity is added in increments of 3 MW, 4 MW or 5MW for the

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251 *Id.* at ¶ 109.

252 *Id.* at ¶ 112.

253 *See also* Micsa Declaration at ¶29.

next 30 years. Thus, the cost of a re-rate is significantly lower than the cost of the battery storage capacity proposed by WGD.

As indicated in the Declaration of Catalin Micsa, transmission line re-rates can be low cost alternatives that should always be an alternative for relatively small overload (less than 12-15%).[254] The ISO is routinely considering the potential for line re-rates in its planning assessments by taking advantage of better technology and increased access to accurate environmental data. This allows for more precise rating assumptions compared to the generally conservative assumptions traditionally employed by transmission owners in the past. For example, all old PG&E equipment is rated based on assumptions of 2 feet/second wind speed. However based on actual wind speed data collected in the area at peak periods, a rerate can most likely be considered based on 4 feet/second for most counties in the PG&E service territory and based on 3 feet/second on a few select counties. The re-rate can only be considered on a line by line basis because the line also to check that its clearance is sufficient to manage the extra sagging that may result from higher current flowing through the line. The ISO has a reference document which provides guidelines that allow the ISO to estimate, for all conductor sizes, the composition material of the line, and voltage levels in order, whether a successful re-rate will mitigate the expected small overload. The re-rated levels for the Vaca-Madison line were consistent with the guidelines in the reference document. The ISO expected that the re-

254 The ISO's Reliability Assessment for the 2010 Planning process showed a small overload on the Madison-Vaca Dixon Line – 1% in 2014 and 4% in 2019. Preliminary Reliability Assessment study results at 25 (Attachment HH).

rating would increase the rating of the line by approximately 12-15% by applying these guidelines.[255] Because the Vaca-Madison 115 kV line loading is increasing at a rate of about 1% per year, a successful re-rate should mitigate the reliability need for approximately 19 years based on these specific conductors and actual line data.[256] .

The ISO concluded that a successful rerate would mitigate the reliability need for approximately 12-15 years based on these specific conductors and actual line data, thereby moving the need for a transmission project to 2027-2030 timeframe.[257] Rerating the line from a 2 feet/second wind speed to 4 feet/second wind speed, where possible, is technically feasible and has been implemented successfully at numerous locations across the ISO's footprint.[258] As the ISO concluded, once the line was successfully re-rated to a higher value, there was no thermal overload or any other reliability problem.[259] Accordingly, re-rating of the line clearly represented the most cost effective remedy to address the identified reliability need. Neither WGD's March 2, 2010 letter to the ISO, its complaint, or the affidavit of Ms. Mueller raise any objections regarding the line's updated rating or offer any evidence that the updated line rating is incorrect or

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255 Micsa Declaration at ¶29.

256 *Id.* See the 2010 ISO expansion plan at: http://www.caiso.com/2771/2771e57239960.pdf where the 105% loading in 2019 minus 100% loading in 2014 divided by 5 year results in 1% per year.

257 Micsa Declaration at ¶29.

258 *Id.*

259 Attachments S and U. Micsa Declaration at ¶29.

unjustified from an engineering basis. Accordingly, WGD offers no substantive basis for overturning the ISO's decision.

WGD's claims that the ISO allowed its planning assumptions to be updated in order to eliminate the need for WGD's project and that the ISO should not allow PG&E to arbitrarily change its line ratings in order to avoid independent transmission should be rejected for the same reasons discussed above with respect to Potrero. The ISO documented that it was relying on re-rating of the Madison-Vaca Dixon line in the draft Transmission Plan, the ISO's presentation at the February 16, 2010 stakeholder meeting, and the final 2010 Transmission Plan which contains the final reliability study results, and in the ISO's May 5, 2010 letter to WGD.[260] Thus, the ISO followed its tariff requirements in this regard. WGD never objected to the revised line ratings during the stakeholder process, and, in its complaint, WGD does not contend, or offer one iota of evidence, updating the line rating was unjustified and unsupportable from a technical perspective. Accordingly, WGD has proffered no basis for overturning the ISO's findings. The ISO is the entity ultimately responsible for maintaining reliability on the transmission grid. Further, the ISO would be violating the NERC planning standards, and potentially be subject to penalties -- or worse yet, future operational reliability problems -- if the re-rating did not eliminate the identified overload problem and the ISO failed to plan for another project to be built to address the issues. Under these circumstances, it strains credulity for WGD to

260 Attachment II to the 2010 Transmission Plan; Complaint, Attachment S..

claim that the ISO is arbitrarily accepting line re-ratings that are no supportable and which do not resolve identified reliability problems.

Finally, the ISO notes that in the affidavit of Mr. Alaywan, WGD's cost and rate witness, Mr. Alaywan admits that the cost of PG&E building a transmission project alternative (as opposed to re-rating the line) would be less than approving the installation of WGD's Madison storage project. In that regard, Mr. Alaywan concludes that the NPV of the Madison storage project's yearly revenue requirement is $30,603,295, and the NPV of a PG&E reconductoring project's yearly revenue requirement is only $27,153,708. Mr. Alaywan does not appear to state exactly what re-conductoring project he is talking about. It must be noted that there is no ISO-approved PG&E project to address the previously identified reliability need; because the reliability need was eliminated by the re-rate. To the extent Mr. Alaywan is basing his cost comparisons on PG&E's Vaca-Dixon-Davis 115 kV Conversion, that project does not compete with WGD's Madison storage project and does not address or resolve the specific reliability need that the Madison-Vaca re-rate achieves.[261] In any event, by the admission of WGD's own cost and rate witness, a PG&E transmission reconductoring project would more cost-effective than WGD's Madison storage project. Alaywan Affidavit at 27-28. It is illogical for WGD to claim that the ISO should have approved its Madison Storage Project proposal under these circumstances.

6. Tulucay 60 KV Energy Storage Project

[261] Micsa Declaration at ¶31.

In paragraph 113 of her affidavit, Ms. Mueller states that WGD proposed the Tulucay Storage project to address the 2010 CAISO Local Capacity Technical Analysis, which indicated that the Vaca-Dixon-Tulucay 230 kV line will reach 100% of its emergency rating for loss of the Vaca Dixon-Lakeville 230 kV line with the Delta Energy Center offline, and that this reliability problem caused a LCR of 787 MW to serve load in the Lakeview Sub-Area. In its request window submission form, WGD proposed to install a battery at the Tulucay bus to address the LCR need. Ms. Mueller notes that the ISO rejected the proposed storage project because (1) it did not mitigate the potential overload on the parallel Vaca-Dixon-Lakeville line and (2) the ISO had previously approved the Vaca-Dixon-Lakeville and Vaca-Dixon Tulucay reconductoring project (which resolved the identified reliability needs in the area) which it had failed to model in its reliability assessment. Ms. Mueller also claims that WGD was not aware of the overload on the Vaca-Dixon-Lakeville line at the time it submitted its project in the transmission planning process request window, and that a simple solution to the additional overload would be to alter the point of the interconnection of the WGD storage project from Tulucay to Lakeville so that the battery can resolve both constraints.[262] Ms. Mueller provides no evidence or support for her conclusion the battery can eliminate both contingencies if it is moved from Tulucay (as proposed by WGD in its request window submission) to Lakeville.

As the ISO indicated in the 2010 Transmission Plan (Attachment U, p. 65), the ISO Board previously approved a project to reconductor both the Vaca-

262 Mueller Affidavit at ¶ 118.

Dixon-Tulucay and Vaca-Dixon-Lakeville 230 kV lines. Once completed, this project will resolve all of the overloads previously identified in both the ISO's long-term capacity technical study and the ISO's Reliability Assessment (Category C overloads on the two lines) in the area on a long-term basis. On the other hand, WGD's proposed storage project only resolves (*i.e.,* reduces the LCR requirement) for the most critical contingency. identified in the 2010 local capacity technical study and does not resolve either of the two Category C overloads identified in the ISO's Reliability Assessment.[263] In accordance with Section 24.2.3.1 of the ISO tariff, the ISO should have rejected WGD's Tulucay storage project as part of the ISO's screening process that it performs for request window submissions. In Section 24.2.3.1 provides that a proposal can only be included in the Unified Planning Assumptions or Study Plan upon a determination that "the proposal is not functionally duplicative of transmission upgrades or additions that have previously been approved by the CAISO." Because WGD's Tulucay storage project is functionally duplicative of the previously approved project to reconductor the Vaca-Dixon-Tulucay and Vaca-Dixon-Lakeville lines, the ISO should have rejected WGD's proposed project *ab initio.* The ISO also acknowledges that it failed to include the Board-approved reconductoring project as part of its Uniform Planning Assumptions as required by Section 24.2.1(2) of the ISO tariff. However, that omission does not change the end result – the ISO should not even have processed WGD's application in accordance with its Tariff,

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263 The ISO's LCR reports clearly state that they are intended to identify the most critical LCR contingency and associated LCR requirements (*see, e.g.,* 2012-2014 Local Capacity Technical Analysis at 25, 29, 30 etc.) not the numerous underlying contingencies that might exist in an area.

and the battery storage project is not needed because it fails to resolve all of the identified reliability needs.

According to WGD, the Tulucay Energy Storage "will reduce overall Local Capacity Requirement (LCR) for the North Coast/North Bay area by 42 MW". The ISO evaluated this proposal as an LCR-related project just as WGD had proposed in its request window submission form and provided its finding in both the 2010 ISO Transmission Plan and the letter that was sent to WGD on May 5, 2010. Based on an analysis from an LCR perspective, the ISO found that the 25 MW real power output from Tulucay Energy Storage can relieve power flow on the Vaca Dixon-Tulucay 230 kV MW line triggered by the outage of the Delta Energy Center and the Vaca Dixon-Lakeville 230 kV Line (the limiting facility and the most critical contingency for LCR in North Coast/North Bay area that was identified in the 2010 LCR study report). However, the battery storage unit exacerbated loading on the parallel 230 kV line (Vaca Dixon-Lakeville 230 kV) with the outages of Delta Energy Center and the Lakeville-Tulucay 230 kV line (an underlying contingency). Consequently, from an LCR perspective, the Tulucay storage project would not provide the level of benefits claimed by WGD, and would only address one of the overloads.[264] On the other hand, the

[264] In any event, in order to address the ISO's LCR resource needs, the battery storage unit would need to function as a generator, not as a transmission element, because it would need to generate real power to the grid to provide LCR reduction and reduce load on the limiting facilities. As confirmed by the Request Window submission by WGD, figure 2 in the WGD application form shows this project generates only 25 MW of real power. No reactive power is generated from the proposal. Moreover, the Commission found that the battery storage unit could only function as a transmission element to resolve reliability problems and not as a generator. Thus, it is not the type of resource that can be procured by load serving entities or the ISO to satisfy resource adequacy requirements.

reconductoring project previously approved by the ISO Board would resolve all LCR issues in the area with a more significant LCR reduction.

WGD's complaint and Ms. Mueller's affidavit do not challenge the fact, that as proposed in its request window submittal, WGD's project, unlike the Board's previously -approved PG&E project, only addresses problems on one of the two lines (from an LCR perspective) and does not resolve any of the reliability performance problems which exist on both lines -- as identified in the ISO's Reliability Assessment study results. Instead, Ms. Mueller claims that WGD was not aware of the overload on the Vaca-Dixon-Lakeville line when it submitted its application, and as such identified Tulucay as the point of interconnection for the Battery storage unit.[265] She suggests that WGD would have proposed a reconfiguration of its proposal if it had known that there were reliability problems on two lines that needed to be addressed. *Id.* She then makes the conclusory claim, without providing any supporting data or analysis, that if WGD's project proposal submission were revised to move the battery unit to Lakeville, then the storage battery would solve both reliability problems.[266] As discussed in greater detail further below, there is no merit to that claim.

WGD failed to realize that the ISO's 2010 Reliability Assessment study results showed that there were overloads on both lines, as opposed to the one overload that was identified in the local capacity technical study, the purpose of which is only to identify the most critical contingency for purposes of determining

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265 Mueller Affidavit at ¶ 118.

266 *Id.*

LCR requirements. In other words, WGD failed to review the results of the Reliability Assessment and relied on the wrong study. In that regard, Ms. Mueller states that WGD relied on the 2010 Local Capacity Technical study as the basis for its conclusion that there was only one reliability problem in the area that needed to be addressed (an overload on the Vaca-Dixon-Tulucay 230 kV line).[267] WGD should have relied on the ISO's September 15, 2009 Reliability Assessment study results which identified Category C overloads both on the Tulucay-Vaca Dixon line and the Vaca Dixon-Lakeville Line (Attachment JJ).[268] Given that WGD relied on the results of the Reliability Assessment study as the basis for submitting other projects in the request window, and the study was available for two months before WGD submitted its request window submission form, WGD has no valid excuse for claiming that it was unaware that there were reliability problems on both lines. As discussed below and in the Declaration of Ponpranod Didsayabutra, in terms of resolving the needs identified in the ISO's Reliability Assessment, WGD's proposal is not sufficient to mitigate the overloads on both lines.

WGD's unsupported claim that simply moving the point of interconnection of battery storage unit from Tulucay (as proposed by WGD in its request window submission) to Lakeville can resolve both of the identified reliability concerns is not only a brand new proposal more than one year after WGD submitted its request window submission form, it is also incorrect. The ISO has looked at this

267 *Id.* at ¶ 113.

268 As indicated above, though, these reliability contingencies were included because the ISO failed to model the reconductoring project previously approved by the Board which resolves all LCR and reliability-related overloads on the two lines

recent proposed revision to WGD's project, and the ISO's analysis shows that, regardless of where the battery storage unit is placed, it does not resolve the two overloads identified in the Reliability Assessment.[269] Thus, even if the ISO were to approve a battery storage project, it would still need to move ahead with the reconductoring of the two lines in order to resolve both reliability performance problems. This would add unnecessary costs to the reconductoring project already approved by the Board, essentially making the costs of the battery purely additive and unnecessary to ratepayers. [270]

As shown in figure 1 of Mr. Didsayabutra's Declaration, neither installation of battery storage unit at Tulucay (figure 2 of Mr. Didsayabutra's Declaration) or Lakeville (figure 3) of Mr. Didsayabutra's Declaration will eliminate this overload. The overload on this line remains, and placement of this battery storage unit at Lakeville substation only reduces only 1.7% power flow on Vaca Dixon – Tulucay

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269 As discussed in Mr. Didsayabutra's Declaration, moving the battery from Tulucay to Lakeville would not resolve the additional overload on the other line. Rather, it reduces power flow on an underlying limitation that can be identified by performing simple power flow studies. As WGD indicated it performed the study to support this project using the 2010 CAISO LCR case, and should be able to easily determine this limitation. Second, WGD did not provide specific location of the new interconnection point that may impact the cost of interconnecting the battery. However, assuming the Lakeville 60 kV bus is an alternative location, this new location will not yield the same LCR reduction benefit on the most critical contingency as connecting at Tulucay 60 kV. For the most critical contingency, placing a battery at Lakeville is approximately only 62% as effective as placing a battery at Tulucay in term of reducing power flow from Vaca Dion to Tulucay, Consequently, even though placing a battery at Lakeville may reduce power flow on Vaca-Tulucay following the most critical conditions and Vaca – Lakeville following underlying contingencies, the benefit from placing the battery at Lakeville is far less than installing at Tulucay.

WGD's analysis also does not acknowledge the fact that any LCR reduction from a battery would be very small compared to what a line reconductoring can achieve. While the LCR reduction is relatively small (and even smaller when the unit is moved to Lakeville), a reconductoring of the two line will significantly reduce the LCR requirement in the area compared to the battery.

270 *See* Didsayabutra Declaration at ¶ 34.

230 kV Line from 109.9% loading to 108.2%. following the outages of the Vaca Dixon-Lakeville and Geyser 9-Lakeville[271] Placement of the battery at Tulucay reduces only 3.1% of power flow on Vaca-Dixon-Tulucay 230 kV line from 109.9% loading to 106.8 percent.[272]

Similar results were found with respect to the potential overload on Lakeville - Vaca Dixon 230 kV line. As shown in figure 4 of Mr. Didsayabutra's Declaration, the 2010 ISO Transmission ISO Transmission Plan report[273] identified the Lakeville - Vaca Dixon 230 kV Line can be overloaded following the outages of Geysers 9 – Lakeville and Tulucay-Vaca Dixon 230 kV Lines. Study results show that neither installing the battery storage unit at Tulucay (figure 5 of Mr. Didsayabutra's Declaration) nor at Lakeville (figure 6 of Mr. Didsayabutra's Declaration) will eliminate this overload.[274] The overload on this line is still exists, and placing the battery storage unit at Lakeville substation reduces only 1.9% of power flow on Lakeville - Vaca Dixon 230 kV Line from 111.7% loading to 109.8%.[275] Placement of the battery at Tulucay sub-station reduces on 1.9% power flow on Vaca-Dixon-Tulucay 230 kV line from 111.7% loading to 109.8%.[276]

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271 *Id. at* _¶ 36._____.

272 *Id.*

273 Table 3-3.2.3, page 47 of the 2010 ISO Transmission Plan report (http://www.caiso.com/2771/2771e57239960.pdf)

274 *Id.* at ¶ 37. _____.

275 *Id.*

276 *Id.*

Based on this analysis of WGD's recent proposal to revise a project that was rejected almost a year ago in the previous planning cycle, as well as the analysis underlying the ISO's assessment of WGD's LCR proposal as reflected in the 2010 Transmission Plan and in the May 5 letter to WGD, WGD's claim that the battery storage solution is a cheaper solution is not only based on a flawed and biased cost analysis, it fails to recognize that the battery solution does not solve the overloads on either the Vaca Dixon-Lakeville or Vaca-Dixon-Tulucay lines, and for LCR purposes only mitigates the overload on one line. On the other hand, the reconductoring project previously approved by the Board resolves all LCR-related overloads and overloads identified in the Reliability Assessment. Thus, it moots the need for a battery storage solution. Stated differently, even if the ISO approved installation of a battery, reconductoring would still need to be undertaken. WGD's analysis does not take into account these additional costs. [277] Thus, WGD has not provided an "apples-to-apples" comparison of the two projects. The end result is that under any scenario, installation of a battery storage unit is not the best cost effective solution for resolving the two reliability problems in this area. The costs of WGD's battery storage project are purely additive to the costs of the reconductoring project previously approved by the Board which solves all of the overloads in the area unlike WGD's proposal.

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277 WGD uses a capital cost of $40 million for PG&E to reconductor the two lines, and a capital cost of $37.5 million for the battery storage unit. WGD fails to account for the fact that if the ISO were to approve installation of a battery, reconductoring would still need to occur and these costs would need to be added to the cost of the battery storage project . Thus, the battery storage alternative is not a cost effective alternative. The ISO also notes that WGD states that the capital cost of its project is $40 million, but Mr. Alaywan's affidavit states that the capital cost is $37.5 million. Nowhere does WGD or Mr. Alaywan explain their inconsistent cost numbers.

Ms. Mueller also alleges that there is an interim operating procedure in place until the transmission project previously approved by the Board is placed in service to drop load. Ms. Mueller alleges that the ISO failed to provide necessary such notice and obtain Board approval of load interruption in lieu of building transmission.[278]

In its May 5, 2010 letter to WGD[279] and the 2010 Transmission Plan on page 65, the ISO noted that, in the interim until PG&E's reconductoring project is completed, sufficient in-area generation has been procured each year to ensure that overloads will not occur on the lines. In addition, PG&E has an operating procedure to open the parallel line (open Vaca Dixon-Lakeville following the outage of Vaca Dixon-Tulucay and vice versa), which can be used to prevent overloads on the two lines. The procurement of sufficient local capacity and the operating procedure are essentially *interim* solutions until the Board-approved project to reconductor the Vaca Dixon-Tulucay and Vaca Dixon-Lakeville 230 kV lines is completed. This operating procedure will simply shift power flows in the area and will not result in load shedding.[280] Thus, Ms. Mueller's conclusory claim that the ISO is shedding load under the interim operating procedure is incorrect. In any event, the ISO Board has previously approved a permanent transmission project – reconductoring the Vaca-Dixon-Tulucay and Vaca-Dixon-Lakeville 230 kV lines – in lieu of load shedding. This project resolves all LCR overloads and the Category C overloads that were previously identified.

278 Mueller Affidavit at ¶ 117.

279 Attachment S at 5.

280 Didsayabutra Declaration at ¶ 39.

In summary, WGD fails to show that the ISO violated its tariff with respect to its treatment of WGD's proposed Tulucay storage project.

7. WGD's Guernsey 70 kV Storage Project

Ms. Mueller notes that WGD proposed the Guernsey Energy Storage project to address a Category A thermal overload on the Corcoran 70 kV transformer bank as outlined in the ISO's Reliability Assessment Results.[281] Specifically, WGD proposed to install a 7 MW battery at the Guernsey substation at an initial capital cost of $10.5 million, and add Capacity in increments of 1 or 2 MW every five years until the total battery capacity equals 14 MW. In its request window submission, WGD compared its project to PG&E's proposal to convert the Guernsey 70 kV sub-station to 115 kV operation, add a new transmission line from Guernsey to the GWF switching station, and convert the Corcoran-Guernsey kV line from 70 kV to 115 kV operation. WGD alleged that this set-up would leave Jacob's Corner on a radial feed from Henrietta. WGD noted that the cost of PG&E's proposed 115 kV conversion project was in the range of $10-$15 million, and claimed that WGD's proposal had a lower annualized revenue requirement. [282]

In the 2010 Transmission Plan, the ISO noted that the Corcoran 115/70 kV bank was identified as overloaded under NERC Category A conditions. The ISO stated that the appropriate mitigation solution was to replace the existing,

281 Mueller Affidavit at ¶ 119.

282 *See* Attachment T.

extremely old transformer with a new standard transformer.[283] The ISO rejected the battery storage solution for the reasons set forth in the 2010 transmission plan, which were reiterated in the ISO's May 5, 2010 letter to WGD.[284]

In its March 2, 2010 letter to the ISO, WGD noted that the ISO's 2010 Transmission Plan approved replacement of the Corcoran Transformer to address the Category A overload.[285] WGD also noted that PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) had additional plans for the area: for example, PG&E was considering converting the Guernsey 70 kV substation to 115 kV, adding a new 115 kV transmission line from Guernsey to the GSF switching station, and converting the Corcoran-Guernsey 70 kV line to 115 kV operation. WGD noted that the cost of such a project would range from $10 and $15 million, and that did not include the cost of replacing the transformer that the ISO had approved WGD noted that the *initial* capital cost of its project was $10.5 for 2010, and the NPV for the project was $71.9 million.[286]

In the ISO's May 5, 2010 letter to WGD, the ISO noted that under the ISO tariff only PTOs with a PTO Service Territory are permitted to build a reliability upgrade located in their service territory, and that WGD was not a PTO with a PTO Service Territory. The ISO also demonstrated that WGD's claim that the

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283 2010 Transmission Plan at 173-74 (Attachment U).

284 *See id.* at 173-74 (Attachment U); Complaint, Attachment S at 10-11.

285 Complaint, Attachment R at 19.

286 *Id.* at 20.

battery storage solution was the least cost alternative to address the identified reliability need was incorrect.[287]

The sole solution adopted by the ISO was to replace the existing Corcoran transformer with a new transformer. The ISO estimated the cost of the transformer replacement project to be $10- $20 million, and PG&E's estimated cost of the transformer replacement was $5-10 million.[288] The ISO also pointed out that WGD's March 2, 2010 letter incorrectly assumed that the costs of PG&E's previously identified Guernsey 70KV to 115 kV conversion project alternative should be included as part of the total PG&E project costs along with the transformer replacement. The ISO indicated that it had not found an identified reliability need for PG&E's conversion project and, as such, WGD's cost assumptions were incorrect.[289] Thus, any of the costs associated with that project – for which the ISO did not find a need and which PG&E was not even pursuing because it was instead opting for just the transformer replacement (*see* Attachment KK)–could not legitimately be considered by WGD. Stated differently, in its cost comparison analysis, WGD was attempting to include the costs of a PG&E project that the ISO had not approved.

In the May 5 letter, the ISO also The ISO noted that the initial capital cost of WGD's Guernsey storage project was $10,500,000; with additional capital costs to be incurred proportionately as the battery capabilities increase every five years from 7 MW to 14 MW. The ISO explained that WGD's cost estimates for

287 Attachment S.

288 Attachment KK.

289 Attachment S.

its project did not include the additional costs that would have to be incurred – for two Special Protection Schemes (SPS) and replacement of an existing, 79 year-old transformer -- if the ISO were to approve the battery project, as well as the increased operational complexity that would result from such a decision. [290]

Further, if the ISO were to approve the battery storage project, additional costs would still have to be incurred to replace the existing transformer with a new standard transformer. The transformer that will have to be replaced dates back to 1931 and has been slated for replacement in 2013.[291] Installing the new transformer now not only resolves the identified reliability need, it replaces an ancient transformer that would need to be replaced anyway in the next couple of years. WGD fails to include the costs of a replacement transformer in its cost analysis. Thus, WGD significantly understates the costs that would be incurred if the ISO were to approve the battery storage solution; the costs of the battery are

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290 Complaint, Attachment S. In her Affidavit, Ms. Mueller claims that WGD's proposal never suggested changing the configuration of the 70 kV system. She states that Guernsey has a normally open breaker in its current configuration to prevent overloads from the Corcoran Source in the event that the Henrietta SPS is activated. She also states that this breaker will remain open, and WGD's proposal never suggested otherwise. She claims that the request window submission stated that the storage unit could be placed at either Corcoran or Guernsey and indicated that Guernsey would need to be transferred over to a Corcoran source in the event that the storage device is placed at Guernsey. Ms. Mueller claims that because the proposal never suggested closing both breakers at Guernsey or interrupting the Henrietta SPS, there would not be any additional costs that would need to be incorporated with regard to the SPS. Mueller affidavit at ¶ 123.

The ISO notes that WGD's project submission for the Guernsey Project) did not provide a clear description of the system under normal conditions and focused instead on emergency condition operations. Guernsey Storage Project Request Window submission at 9. Although WGD's submission indicated that if the battery storage unit is installed at Guernsey and the sub-station if served from Corcoran, the submission did not state that the existing main feed from Henrietta would need to be changed so that it is open under normal conditions. The ISO acknowledges that if Guernsey is only served from Corcoran in a radial configuration, then the two additional SPSs the ISO identified in the 2010 Transmission Plan and in its May 5, 2010 letter would not be needed. However, as discussed herein, that does not change the ISO's prior decision because the battery option remains a higher cost alternative.

291 Micsa Declaration at ¶¶32, 34.

purely additive costs that ratepayers would have to incur in addition to the costs of the new transformer that will be required anyway. WGD's proposed battery storage solution is obviously a higher cost alternative.

Finally, Ms. Mueller states that the ISO only provided the capital costs of the two projects, which she asserts is not enough to determine the least cost alternative.[292] As an initial matter, it is not clear to which projects Ms. Mueller is referring. The only project being approved is replacement of the existing transformer; the ISO is not approving any other PG&E upgrade or addition to address this reliability concern. Ms. Mueller's claim is also belied by the conclusions in the affidavit of Mr. who In his affidavit, Mr. Alaywan concludes that the NPV of the Guernsey storage project's yearly revenue requirement is $35,565,710, and the NPV of the PG&E Guernsey Area Reinforcement's yearly revenue requirement is only $29,093,258.[293] Thus, by the admission of WGD's own rate and cost witness, WGD's Guernsey storage project would not be the most cost-effective means of resolving the identified reliability need in the area even if the ISO's approved solution had been to approve the Guernsey Area Reinforcement Project.

F. The TTS/WGD Cost Analysis and Related Claims Are Misplaced and Deeply Flawed

1. TTS' and WGD's General Assertions Regarding Cost Comparisons

Complainants assert that the ISO failed to provide substantial evidence, including a comparative cost analysis, to properly compare TTS' and WGD's

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292 Mueller Affidavit at ¶ 124.

293 Alaywan Affidavit at ¶ 27.

proposed projects with the alternatives the ISO adopted.[294] The Complainants' cost witness Alaywan provides a cost analysis purporting to demonstrate that five of WGD's storage projects and two of TTS' Static Var Compensator projects[295] would result in lower costs to ratepayers than the PG&E alternative reliability projects approved by the ISO.[296] Specifically, Mr. Alaywan alleges that the NPVs of the annual revenue requirements for these projects are lower than the NPVs of respective competing projects.

It is significant that Mr. Alaywan makes no such claim for the other TTS and WGD projects.[297] Mr. Alaywan's own analyses submitted with the Complaint show that there are increased costs to ratepayers for WGD's Madison and Guernsey storage battery projects (and the Stockton storage project which Ms. Mueller does not substantively discuss in her affidavit).[298] Thus, even the Complainants' own analysis – which the ISO demonstrates is deeply flawed and seems to be skewed toward making the WGD and TTS alternatives appear to be lower cost alternatives – shows that the remaining WGD projects discussed in the complaint are more costly than the alternative reliability projects approved by the ISO. Mr. Alaywan's analyses are also limited to two of the seven TTS projects addressed in the Complaint. Notably, Mr. Alaywan provides no cost comparison for the Maple Creek, Garberville, Camp Evers, Cal Cement, or Trinity

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294 Complaint at 22-23.

295 This cost analysis addresses WGD's Placer, Coppermine, Weedpatch, Tulucay and Potrero projects and TTS' Old River and Watsonville projects.

296 Alaywan Affidavit at ¶¶ 61-64.

297 *Id.*

298 *See* Attachment A to the Alaywan Affidavit at page 2.

projects.[299] Complainants' own evidence therefore establishes that there was no cost basis for the ISO to designate WGD and TTS to build these seven of the projects addressed in the Complaint.

With regard to seven projects for which Mr. Alaywan asserts economic benefit, Complainants' analysis is fundamentally flawed. Even if it made sense for the ISO to compare: (1) the costs of WGD and TTS building a reliability project that they are not (as discussed above) authorized to build to (2) the costs of a PTO with a PTO Service Territory building the project, it would not be appropriate or useful for the ISO, as Mr. Alaywan suggests, to apply individual company-specific cost estimates provided by project developers for purposes of deciding between competing proposals. The Commission has acknowledged the shortcomings of such an approach in the RTPP Order.[300] As the ISO has previously described,[301] in order to determine the best, cost-effective solution to resolve an identified need, the ISO generally applies planning level costs, which reflect current cost benchmarks for the standard components involved in building or upgrading transmission facilities (*e.g.,* cost per mile of transmission line construction, substation equipment, transformers). These planning level costs must be based on consistent assumptions, as the objective is to assess

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299 *See* Attachment B to the Alaywan Affidavit.

300 *California Indep. Sys. Operator Corporation, et al.,* 133 FERC ¶ 61,224 at n.134, n.165. and P 224.

301 *See, e.g.,* California Independent System Operator Corporation Tariff Amendment Filing, at 66, Docket No. ER10-1401 (June 4, 2010) ("Docket No. ER10-1401 Transmittal Letter"); Answer to Comments, Motions For Leave To Answer And Answer to Protests of the California Independent System Operator Corporation at 91-93, ("Docket No. ER10-1401 Answer to Protests") Docket No. ER10-1401 (July 15, 2010); Initial Comments of the California Independent System Operator Corporation at 15-16, Docket No. RM10-23 (September 30, 2010).

fundamental and sustained cost implications, not transitory cost differences potentially arising from changes in financing structures, *etc.* These planning level costs reflect current costs in California and are specifically intended for use in determining the most cost-effective transmission facilities to meet an identified need. Using these planning level costs allows the ISO to provide a relative cost comparison between materially different facility alternatives that could meet the indentified need. For example, there may be several available paths to transmit energy from a particular source to a particular sink on the grid. One path may require a 100-mile transmission line, while another path may require a 50-mile line. All else being equal, the 50-mile line would have a significantly lower cost than the 100-mile line. It may be the case, however, that each line requires somewhat different substation upgrades or other new equipment. The ISO would use planning level costs to estimate the overall cost of each interconnection path and assess which one meets the need most cost effectively.[302]

On the other hand, using cost estimates provided by a competing project developer to compare the costs of it building a project compared to the purported costs of some competitor building a project is problematic because such company-specific estimates are not reliable and can be manipulated. The goal of a project sponsor in submitting a cost estimate is to submit the winning proposal, which creates incentives to "low-ball" the projected cost. Hence, such estimates

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302 The ISO tariff does not require the ISO to approve the reliability project proposed by the PTO if it is not the best solution. Thus, under the ISO's transmission planning process, ratepayers are not required to pay for PTO projects that are technically inferior to and not as cost effective as non-PTO proposed projects. The ISO evaluated the battery storage solutions proposed by WGD and found that they were not the best, cost-effective solutions for the reliability needs identified by the ISO.

are unreliable. Indeed, the ISO's own transmission planning experience shows that often there are significant differences between the estimated cost and the actual cost to build the project. Moreover, the ISO has no ability to require that only the submitted cost estimates be reflected in rates. The Commission agreed with this analysis in the RTPP Order, finding that cost estimates are not reliable when developers are competing to build projects, and such "criteria would provide an incentive for project sponsors to deliberately underestimate their costs."[303]

There are other general problems associated with using cost estimate numbers provide by a project developer to compare the costs of its building transmission project to the costs of some other developer. For example, because individual company cost components (*e.g.,* return on equity, capital structure, O&M, and A&G) will vary over time, it is inappropriate to take a snapshot of such company-specific costs at a single point in time – before construction of the project has even commenced – and assume that those will be the company's costs associated with owning, operating, and maintaining the project over its lifespan as Complainants have done in this Complaint.

Also, a project developer may build a project and then "flip it" to some third party with higher O&M or A&G (or other costs) after the project is built. This scenario, which has already occurred for transmission projects constructed within the ISO footprint and which could increase the costs of an approved project, would not be captured in the initial cost analysis, yet could result in an

303 RTTP Order at PP 223-24.

“erroneous” decision to approve a project (that would not have been approved if the new owner were the original project sponsor) that actually turns out to be the higher cost project in the long run.

Further, the ISO is in no position, within its transmission planning process, to determine which company specific O&M and A&G (and other costs such as return on equity) costs will result from, and be allocated to, a particular transmission project over the entire life of that project. O&M and A&G costs levels and the allocation of such costs are issues typically handled in a rate case proceeding before a regulatory agency. The ISO is not a ratemaking body; yet, if WGD’s and TTS’ approach to transmission planning of basing decisions on artificially precise developer-specific financing, construction, and O&M costs were to be adopted, the ISO would essentially be required to conduct rate cases, hold hearings, and take evidence for every sponsor that submits a project. That would bring transmission planning to a grinding halt and cause ISO costs to skyrocket.

Indeed, WGD and TTS have not even provided a detailed accounting, the underlying basis, or any back-up support that the ISO could use in assessing their purported O&M and A&G costs. For example, Mr. Alaywan estimates that WGD’s O&M and A&G costs associated with the battery storage unit are 2.50 percent.[304] However, Mr. Alaywan offers only a conclusory statement to support his claim that this is the appropriate amount of O&M and A&G for WGD. Mr. Alaywan does not provide any objective evidence to support his number or show

304 Alaywan Affidavit at ¶ 57.

why it is just and reasonable. These costs are apparently not based on the costs of other companies that have operated battery storage facilities. Thus, there is no basis to assess and validate the reasonableness of WGD's and TTS' cost estimates and determine whether they capture all of the costs likely to be incurred in connection with the operation of WGD's and TTS' proposed projects.

Finally, although Mr. Alaywan claims that that having WGD construct the aforementioned seven projects would save ratepayers approximately $124 million on a NPV basis,[305] he fails to mention that there is no identified reliability need – and as such no need for any reliability project – in the Coppermine, Weedpatch, and Potrero areas. Adopting the Complainants' position with respect to these three projects would result in millions of dollars in *unnecessary* new costs (on a NPV basis based on Mr. Alaywan's own cost analysis) to ratepayers. With respect to the Placer project, Mr. Alaywan claims that approval of its project instead of the PG&E project would result in over $45 million NPV of savings.[306] Mr. Alaywan fails to mention that (1) the ISO has not approved any reliability project in the Placer area yet; and (2) WGD's storage battery only solves two of the identified reliability problems in the Placer area, while PG&E's proposed project resolves 15 of the identified reliability problems. Mr. Alaywan's failure take into account the costs of resolving the 15 reliability problems that the battery storage unit does not resolve but which PG&E's proposed project does would invalidate the analysis even in the absence of the other flaws. Likewise,

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305 *Id.* at ¶ 64.

306 *Id.* at ¶ 61.

WGD's Tulucay battery storage solution does not resolve the two reliability performance problems identified in the ISO's Reliability Assessment, but the reconductoring project previously approved by the Board does. Because the reconductoring would need to proceed, also implementing an unnecessary battery solution would add over $60 million in unnecessary costs for ratepayers.

It should be noted that Mr. Alaywan's own cost comparison analysis of the Guernsey, Stockton, and Madison-Vaca projects shows that WGD's proposed cost solution is more costly than the other options. Indeed, as discussed above in the specific discussion of Guernsey, the ISO is resolving an identified reliability need by replacing a 79 year old transformer that would need to be replaced in a couple of years anyway. Because the transformer replacement would need to occur even if the ISO adopted a battery storage project, adoption of WGD's proposal would heap an additional (and unnecessary) $35.56 million in costs on ratepayers. Finally approval of WGD's Madison storage project instead of the approximately $100,000 re-rate approved by the ISO, would result in approximately $30.5 million in additional and unnecessary costs being imposed on ratepayers. WGD does not even attempt to discuss the merits of the Stockton storage project because Mr. Alaywan's analysis shows that the solution adopted by the ISO is more than $51 million cheaper than WGD's solution.

Moreover, as noted above, Mr. Alaywan's analyses are limited to only two of the seven TTS projects addressed in the Complaint. Mr. Alaywan provides no cost comparison for the Maple Creek, Garberville, Camp Evers, Cal Cement, or Trinity projects. This suggests that, even using the flawed cost comparison analysis advanced by Complainants, there is no evidence that these projects would save costs for ratepayers.

2. Specific Flaws In The TTS/WGD Cost Analysis

Even if there were value to the type of cost analysis suggested by Complainants, the numerous specific flaws and errors in Mr. Alaywan's analysis would negate that value. As described in the attached declaration of Neil Millar, the WGD/TTS cost analysis inappropriately allocates a full share of O&M and A&G costs to each of PG&E's projects using a "fixed charge rate" based on PG&E's existing system O&M and A&G rates.[307] Specifically, Mr. Alaywan estimates an O&M and A&G rate based on PG&E's total O&M and A&G costs and then divides those costs by gross plant. The rate is then applied against total new capital costs associated with PG&E's projects. In contrast, Mr. Alaywan uses a purely incremental rate to determine the O&M and A&G costs proposed by TTS and WGD.

There is no economic justification for this approach. PG&E's existing system includes an extensive quantity of aged facilities that require increased maintenance. The current O&M and A&G rate for PG&E's entire existing system is thus not representative of the O&M and A&G associated with the new facilities that PG&E is proposing to build. Only the incremental O&M and A&G costs, if there are any, that result from the construction of these projects should be logically considered (although, as describe above, determining such company-specific costs would be speculative at this point in time). Further, it is counter-

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307 *See* Alaywan Affidavit at ¶ 48.

intuitive for Mr. Alaywan to apply additional O&M and A&G charges to replacement projects that PG&E is undertaking such as reconductoring and transformer replacements because PG&E would still be responsible with operating and maintaining the existing equipment regardless or whether reconductoring or transformer replacement were to occur.[308] Indeed, these replacement and reconductoring projects may actually cause a decrease in PG&E's O&M costs because the reconductoring of old lines and the replacement of old equipment should result in reduced maintenance costs compared to the maintenance costs associated with the facilities they are replacing.[309] In contrast, if the ISO were also to approve battery storage, the O&M and A&G costs associate with those new facilities would have to be added to the O&M and A&G costs that are already embedded in PG&E's rates for existing facilities and which would not "be going away."

Even assuming *arguendo* that TTS and WGD had valid incremental cost numbers for PG&E, applying those costs on the basis of gross plant reflecting the year of construction would still be flawed. By applying incremental rates based on gross plant without making any attempt to adjust for inflation, Mr. Alaywan implicitly –and incorrectly – assumes that a new transmission line will require more maintenance today, based on today's costs, than an older transmission line of equal length and configuration, simply because the capital cost of the new line

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308 Millar Declaration at ¶10.

309 *Id.*

has increased due to inflation.[310] That is like claiming because annual maintenance costs on a 20-year old car that originally cost $10,000 are 5 percent, or $500, maintenance cost on a new car, with a $50,000 value, will also be 5 percent, or $2500, when if fact they are likely to be less than $500. As discussed in the affidavit of Mr. Millar, correcting this error alone shows that Mr. Alaywan's calculation of PG&E's O&M and A&G rate is approximately 50 percent too high.[311]

In addition, Mr. Alaywan's analysis regarding A&G costs ignores the fact that PG&E's A&G costs are allocated based on labor ratios, not transmission plant. Thus, there is no basis to attribute a particular amount of A&G costs to an increase in gross plant without an analysis of the increase in labor costs.

As Mr. Millar discusses, Mr. Alaywan's analysis also contains a number of economic modeling errors that materially affect his results. His analysis consisted of determining an annual revenue requirement (which would be recovered from ratepayers in each year) for each project, and then applying a discount rate to reach revenue stream to determine the net present value. Numerous errors in modeling have been made that materially affect his results. While in concept this approach can be useful in considering competing projects, the errors are sufficiently extreme that this analysis, in the ISO's view, is of no use to the Commission in its consideration of this Complaint.

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310 Millar Declaration at ¶11.

311 *Id.* at ¶12.

First, Mr. Alaywan's analysis fails to address the different service lives of the various projects in his determination of NPV. Mr. Alaywan determined the NPV of the calculated annual revenue requirements "for the service life of each project."[312] In making a simple comparison of net present values of different service lives, he considered only the costs – but not the benefits – associated with the extra years of service that a new facility would provide. As discussed in Mr. Millar's declaration, two projects with identical annual revenue requirements in each year of service, but with two different service lives would yield different net present values simply due to the extra years of service, and associated costs.[313] Proper consideration of these end-of-period effects can be accomplished by a number of means, such as by assuming that the longer-lived project is salvaged (with an accounting of salvage costs and salvaged material); assuming the shorter-lived project is replaced at the end of its first service life and performing an NPV over the life of the longer-lived project, or truncating the analysis for both projects to the shorter of the two service lives. For comparative purposes, Mr. Millar has provided a comparison of the last method in Appendix A.1 to his declaration, comparing the PG&E Atlantic Placer Project with the WGD Auburn Project. Calculating the net present value of both the PG&E project and the WGD project over a consistent 25 year period reduces the benefits claimed by Mr. Alaywan by over 16 percent. This error is repeated in all of the projects

312 Alaywan Affidavit at ¶ 39.

313 Millar Declaration at ¶16.

studied; the magnitude of the impact varies with the specifics of each comparison.

Second, Mr. Alaywan's analysis is flawed because he does not consistently apply the discount rates for purposes of calculating net present values of competing projects' annual revenue requirements. Mr. Alaywan's analysis determined annual revenue requirements for comparative purposes by applying each project sponsor's rate of return in determining an annual revenue requirement (which would be recovered from ratepayers in each year) for each project, and then applying a discount rate to reach revenue stream to determine the net present value. However, he erroneously applied the rate of return for each project sponsor to the annual revenue requirement of that sponsor's project. Because the discount rate is intended to determine the net present value to ratepayers of the annualized costs of a project, one must apply a consistent discount rate based on how ratepayers view the present value of a future expenditure.[314]

For comparative purposes, Mr. Millar calculated the net present value of the two annual revenue requirement streams calculated by Mr. Alaywan. This comparison is set forth in Appendix A.2 to Mr. Millar's declaration, comparing the PG&E Atlantic Placer Project with the WGD Auburn Project, using the WGD rate of return as the discount rate for both revenue requirement streams. Correcting this error results in a 15.5 percent reduction in the benefits claimed by Mr. Alaywan for the WGD Auburn project.

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314 Millar Declaration at ¶21.

Mr. Alaywan's errors in applying different discount rates are further compounded – and more readily apparent – in his analysis of the TTS Old River project. Mr. Alaywan compared the annual revenue requirement of the PG&E Kern-Old River Project to the annual revenue requirement of the TTS Old River Interim Solution (for 10 years) accompanied by a deferral (and later construction) of the more permanent PG&E project being deferred by 10 years. Mr. Alaywan applied the lower PG&E rate of return as the discount rate to the Kern-Old River Project proposed by PG&E. He then applied the much higher TTS return on equity (which produces a lower net present value of costs for a given cost/revenue stream)[315] to both the TTS annual revenue requirement for the first 10 years and the PG&E annual requirement for the PG&E project beyond the initial 10 years. Higher discount rates increase the future value of an investment made today, or conversely, higher discount rates applied to a future cost result in a lower valuation of that cost today. For example, at a 10 percent discount rate, a ratepayer could be willing to pay up to $91 this year to avoid a cost next year of $100. However, applying a 5 percent discount rate, a ratepayer would be willing to pay up to $95 to avoid a charge of $100 next year. Applying Mr. Alaywan's methods, two projects that will cost a customer an identical $100 next year would be ranked differently simply by applying different discount rates to each project. In either event, however, the ratepayer is paying $100 next year. There is no reason a ratepayer would be willing to pay different amounts this year to avoid a $100 charge next year just because there is a difference in who is collecting the

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315 *Id.* at ¶26¶.

$100 next year. This apples-to-oranges comparison grossly distorted the net present value analysis.

These flaws on the discount rate pervade all of Mr. Alaywan's analysis. By consistently applying inconsistent discount rates, Mr. Alaywan over-inflates the perceived benefits of all the TTS and WGD' projects.[316]

Finally, Mr. Alaywan inconsistently applies inflation rates to costs. The results produce an artificial advantage to the TTS and WGD's projects.   Mr. Alaywan applied an inflation rate of 2.25 percent to his estimated O&M and A&G costs in determining future annual revenue requirements. Because Mr. Alaywan attributes lower O&M and A&G to his clients than to PG&E, including the impacts of inflation increases the benefits of the TTS and WGD projects.[317]

However, as Mr. Millar has identified in his declaration, Mr. Alaywan has apparently failed to include the implications of inflation in estimating the benefits of TTS projects in potentially deferring PG&E projects.

Mr. Alaywan also points to the benefits of WGD projects being staged expenditures over a period of time. In those cases as well, Mr. Alaywan does not apply inflation to the future staged capital projects, again resulting in an erroneously low net present value for those projects compared to the PG&E alternatives, i.e., he assumes that the cost of installing 1 MW of new battery storage capacity is the same today as it would be 20 years from today. As set out in Appendix A.3 to his declaration, Mr. Millar calculated the impact of this

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316 *Id.* at ¶27.

317 Millar Declaration at ¶29.

correction on the economic evaluation of the TTS Old River proposal. This single correction erodes over 35% of the economic benefit claimed by Mr. Alaywan for this project. Similar results can be expected for the other projects identified above. Mr. Alaywan, however, ignores these results in his analysis. Besides the TTS Old River analysis, failing to include inflation in the capital cost of deferred projects impacts the TTS Watsonville analysis as well as the WGD Coppermine, WGD Guernsey, WGD Weedpatch, WGD Stockton and WGD Madison analyses. The impact for each of these varies to a greater or lesser extent depending on the specific capital cost details.

3. WGD Cannot Provide the "Additional Benefits" that It Claims the Battery Storage Units Will Provide

Mr. Alaywan also argues that WGD's proposed battery storage projects provide ratepayers with additional benefits that wires-based projects cannot provide, including regulation up, spinning and non-spinning reserves, and resource adequacy capacity.[318] He states that these ancillary services would displace what the ISO would otherwise have to procure in the day-ahead and real-time markets, and ratepayers would be provided with the additional savings equal to the cost of the displaced service. Specifically, he alleges that WGD could provide these ancillary services at no additional cost to ratepayers, thereby saving ratepayers approximately $102 million if the ISO had included these benefits in its calculations.

This argument flies in the face of (1) specific representations WGD previously made to the Commission regarding the scope of services their battery

318 Alaywan Affidavit at ¶¶ 65-68.

storage units would provide if the Commission treated them as transmission, and (2) the express limitations the Commission placed on these storage units if they were to be treated as transmission

On November 19, 2009, WGD filed a Petition for Declaratory Order in Docket No. EL10-19 in which WGD requested that the Commission issue a Declaratory Order finding that the battery storage projects that will be used in WGD's proposed projects, as described in its Petition, are properly classified as transmission facilities and eligible for rate-base treatment.[319] Importantly, and directly contrary to the claims WGD makes in its Complaint, WGD stated that "the WGD Projects . . . will only operate in a way to generate electricity when required for reliability reasons."[320] WGD stressed that the projects would not be operated by the ISO but rather would be operated by WGD as a Participating Transmission Owner. In the portion of its Petition for Declaratory Order titled "Significant Benefits of the Proposed WGD Projects", WGD pointed out the various reliability services that the storage batteries would provide and did not identify and ancillary services or capacity benefits, presumably because WGD had already indicated that the units would not be providing any of those services.[321]

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319 *See Western Grid Development, LLC,* 130 FERC ¶ 61.056 at PP 3-5. WGD asserted that the storage units would address transmission reliability problems identified by the ISO and facilitate reliability on the ISO system by addressing voltage drop situations, emergency thermal overloads on transmission lines, and the prevention of the loss of load to retail customers.

320 *Id.* at P 5.

321 *Id.* at P 7. WGD stated that "unlike generation facilities that are operated to sell energy and ancillary services into the CAISO's Energy Markets, the WGD Projects will be operated by WGD as wholesale transmission facilities. Further, "the physical operation of the WGD Projects will be consistent with a determination that the WGD Projects are wholesale transmission

At page 10 of its Petition, WGD distinguished the battery storage units from pumped storage by noting that "pumped storage units are designed to provide *energy* as a capacity resource to the grid. In contrast, [the battery storage resources] are designed to provide *voltage support* to address already identified transmission system reliability issues..."[322]

Thus, completely contrary to the position WGD has taken in this Complaint, WGD indicated in its Petition that its battery storage resources would not provide ancillary services and capacity, and claimed that this was a key factor why the Commission should approve the storage units as transmission facilities.

In support of its Petition, WGD attached an affidavit from Mr. Alaywan.[323] Mr. Alaywan's statements in that affidavit contradict the arguments that he has made in his affidavit in this proceeding. Specifically, in his prior affidavit, Mr. Alaywan definitively stated that the WGD Projects would not participate in the ISO's markets or set prices. He stated:

> 30. The WGD projects will not participate in the CAISO Energy and Ancillary Service and Capacity markets in any shape or form. These WGD Projects are designed to provide transmission service only. Accordingly, the WGD projects will not (a) unduly discriminate against any other CAISO Market Participants who provide the Energy and Ancillary Services; (b) in any way skew the operation of the ISO's markets for Energy and Ancillary Services, or skew the marginal cost of the Energy and Ancillary Services; and/or

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facilities, in part because the WGD Projects will be operated by WGD under the direction of the CAISO just like the operation of all other high-voltage wholesale transmission facilities in California by PTOs." *Id.* at 10.

322 *Id.* at P 13. WGD also claimed that unlike the pumped storage resource that the Nevada Hydro Company sought to have treated as a transmission facility, the WGD Projects would not "compromis[e] the independence of the CAISO and/or distorting energy markets." *Id.* at P 14.

323 Mr. Alaywan's affidavit in support of WGD's Petition in Docket No. EL10-19 is attached hereto as Attachment LL.

> (c) compromise the ISO's Operational Control over one supplier of products sold in the markets that it operates.
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> 31. WGD is seeking for the WGD Projects to be treated like any other transmission assets that provide transmission services under a fixed rate of return without influencing the CAISO markets or other participants in the CAISO's markets. In particular, WGD, unlike other Market Participants, would never obtain revenues from the sale of energy and ancillary services.
>
> 32. The WGD Projects will not be market makers. The principles outlined earlier are fundamental to the WGD projects. As described previously, the WGD Projects will not influence or skew the operation of the CAISO Energy, Ancillary Service and Capacity Markets at any time. The WGD assets will not be operated by the CAISO or the local utility, so there is no question about the proper utilization of these ESDs as transmission assets.

Thus, Mr. Alaywan stated that it was fundamental to the WGD Projects that they would not provide Ancillary Services and Capacity and not skew in any way the operation of the ISO's markets or the marginal price of Ancillary Services and Capacity in those markets.

In its Answer to Protests filed on January 5, 2010 in Docket No. EL10-19, WGD repeated its disavowal of any intent to provide Ancillary Services or capacity.[324] The Commission relied on the assertions made by WGD in its Petition and Mr. Alaywan in his affidavit submitted with the Petition in determining that the WGD projects could be treated as transmission given the conditions that were being placed on their operation. The Commission recognized that the projects would be called upon in the same manner as other transmission assets and would be used to provide voltage support and to address thermal overload

[324] Attachment MM.

situations.[325] The Commission stated that the battery storage units would not be bid into the ISO markets and would not be a market participant in any way; instead, they will be operated only at the ISO's request when system reliability issues require them to provide voltage support to the grid.[326] In response to arguments that the storage batteries would be capable of providing not only voltage support, but also Energy and Ancillary Services products, the Commission stressed that "as proposed, Western Grid will not be bidding the Projects into the ISO markets and Western Grid's projects will be used to provide voltage support and to address thermal overload situations, at the ISO's instruction, which will only arise if there is no other competitive bid to provide the service through the markets."[327]

Accordingly, the Commission stressed that the projects would not be undercutting competitive bids by market participants. In its rehearing order, the Commission again pointed out that the projects would be operated like capacitors "to provide electricity for the transmission grid to maintain system reliability, rather than to act as an energy or capacity resource"; would not be providing competitively procured ancillary services and would not be bidding into the markets, and as such, the projects could not undercut the competitive market prices for ancillary services; and will only be used to provide voltage support and to address thermal overload situations, at the ISO's instruction, only if there is no

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325 *Western Grid Development, LLC,* 130 FERC ¶ 61,056 at P 47 (2010).

326 *Id.* at P 50.

327 *Id.* at P 51.

other competitive bid to provide that service through the markets.".[328] The Commission stressed that the record contained no evidence that the projects would be used in any other fashion.[329]

It is unclear whether Mr. Alaywan is now suggesting that WGD would participate in the ancillary services markets. What is clear is that WGD's proposal to be treated as transmission is premised on the fact that it will not participate in ISO markets. Further, if WGD were able to provide ancillary services and capacity free-of charge, it would – contrary to WGD's prior statements and the Commission's findings – certainly be skewing the ISO markets by reducing market demand regardless of whether it participated in the markets or made capacity available outside the markets. Moreover, under the ISO tariff, the ISO must use its markets to obtain Ancillary Services that are not self-provided.[330] At a minimum, therefore, it is disingenuous for WGD to claim in this proceeding that the ISO was remiss in not counting the ancillary services and capacity benefits the battery storage units would provide when WGD itself attested to the Commission that its resources would not be providing such services.

G. The ISO Adequately Documents Its Consideration of the WGD Projects.

Complainants contend that the ISO failed to document adequately in the 2010 transmission plan the economic and technical analyses that underlay the

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328 *Western Grid Development, LLC,* 133 FERC ¶ 61,029 at PP 11, 15-16.

329 *Id.*

330 *See* ISO tariff section 8.1.

rejection of the WGD projects.[331] Complainants attempt to impose on the ISO obligations that go beyond those set forth the ISO tariff and the transmission planning BPM and for which there is no justification. The ISO tariff has no specific provision requiring the discussion in the transmission plan of rejected project proposals. Section 2.2.1 of the BPM simply requires, with regard to such projects, that the ISO identify "[t]ransmission project proposals ISO management does not approve along with the basis of its decisions." Consistent with Section 2.2.1, the 2010 Transmission Plan discussed each of WGD's project proposals and detailed the reasons that the ISO rejected those proposals.[332]

Requiring the ISO to provide additional detail would be unnecessary and counterproductive. Such a requirement would be unduly burdensome for an operating utility that must dedicate its resources to ensuring reliable service. As it is, the 2010 Transmission Plan consumed 375 pages. Preparing the type of plan envisioned by Complainants would require far more time and resources than is necessary.

Such a requirement would also serve no useful purpose. The transparency that the Commission sought in Order No. 890 is achieved through the public availability of information on which the ISO relies and by stakeholder participation in the planning process, not by a decisional document that includes every minute detail of the ISO's analysis. The ISO is not a regulatory body whose opinions are subject to review according to appellate standards, based on

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331 *See* Complaint.

332 *See* Attachment U, 2010 Transmission Plan at 65-66, 111-13, 153-54, 173-74, 179-80, 188, 276-84.

the written record alone, such that it is critical that the decisional document identify all supporting evidence and respond to every comment individually. A market participant can dispute decisions in the transmission plan through arbitration or by filing a complaint, as Complainants have done here. In each instance, if parties filing a complaint establish a prima facie case, the Commission or the arbitrator can direct evidentiary proceedings, including discovery. No more is necessary. Here, however, the Complainants have failed to establish a prima facie case and are seeking a remedy which is blatantly inconsistent with clear provisions of the ISO tariff. As such, there is no basis for evidentiary proceedings.

H. The Availability of Incentives for Advanced Transmission Technologies Does Not Alter the Criteria for Approving Transmission Project Proposals in the ISO Planning Process.

Complainants contend that the Commission should take into account federal policies encouraging "advanced transmission technologies" – including flexible AC transmission systems ("FACTS") and energy storage devices – when acting on the Complaint.[333] It is true that the Energy Policy Act of 2005 directed the Commission to "encourage, as appropriate, the deployment of advanced transmission technologies."[334] The Commission has responded to this directive, in part, by making transmission rate incentives available for such advanced transmission technologies. Indeed, the Commission conditionally accepted rate

333 Complaint at 2, 24-26.

334 *See* Section 1223(c) of the Energy Policy Act of 2005.

incentives proposed for certain WGD projects based on the use of such advanced transmission technologies.[335]

Nothing in the Energy Policy Act of 2005 or in the Commission's policies encouraging advanced technologies, however, requires the selection of proposed projects utilizing such advanced transmission technologies where the selection would be contrary to the express terms of the system planner's Commission-approved tariff or where the system planner has determined that the project proposals are not the most appropriate option to address a given set of reliability needs. The Commission recognizes that the use of advanced transmission technologies in a project proposal does not trump the role of a utility's transmission planning process in determining which additions or upgrades are needed. For this reason, the Commission conditioned the rate incentives requested by WGD on the approval of the WGD projects in the ISO's transmission planning process.[336] As explained above, the WGD projects were not approved in the ISO transmission planning process, consistent with the applicable terms of the ISO tariff.

Complainants cite *Primary Power*, 131 FERC ¶ 61,015 (2010) and *Central Transmission, LLC v. PJM Interconnection, L.L.C.*, 131 FERC ¶ 61,243 (2010) ("*Central Transmission*") to support a claim that system planners must treat all projects proposed in a transmission planning process alike, even if they are

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335 *See Western Grid Development, LLC,* 130 FERC ¶ 61,056 at P 97 (2010).

336 *Id.* at P 71.

proposed by non-incumbent utilities.[337] As explained above, the ISO acted in a non-discriminatory manner in evaluating the projects proposed by Complainants. Moreover, the Commission has already considered and rejected arguments that these cases require the ISO to ignore provisions of the ISO tariff governing which entities can build certain categories of transmission projects. As the Commission found, the *Primary Power* and *Central Transmission* cases were decided based on specific provisions of the PJM tariff that do not apply to the ISO tariff: "Unlike the CAISO tariff provisions here, in the cases Green Energy relies on, *Primary Power* and *Central Transmission*, the Commission found that the PJM tariff did not establish a [right of first refusal] for incumbent PTOs."[338]

I. Remedies

The remedies requested by Complainants are intended to require the ISO to revisit decisions made in its approved 2009 and 2010 transmission plans with the objective of driving the ISO to approve the reliability projects proposed by the Complainants. The requested remedies could only be implemented if entities other than Participating Transmission Owners with PTO Service Territories are eligible to be designated as the builders of reliability projects in the ISO transmission plan or if the ISO had the authority to direct Participating Transmission Owners designated to build reliability projects to enter into contracts with specific service providers. As explained above, both of these

337 Complaint at 25-26.

338 RTTP Order at P 70 (footnote omitted).

alternatives are contrary to the ISO tariff and the Transmission Control Agreement. On this basis alone, the requested remedies must be denied.

The ISO nonetheless notes a number of other flaws with the remedies requested by Complainants. First, even if the Commission were to find that the existing tariff provisions governing the role of Participating TOs with PTO Service Territories as the sole builders of reliability projects had become unjust and unreasonable or unduly discriminatory, a change to this provision under section 206 of the FPA could only apply prospectively. It could not require the re-evaluation of project proposals already considered by the ISO under the tariff provisions in effect during the past two planning cycles.

Complainants also state that the ISO's evaluations of their project proposals should be based solely on data available as of the date of the relevant transmission plan, rather than on the basis of data that may now be available.[339] Although the ISO expects that there is no need for the Commission to ever reach this issue, this request highlights that the objective of the Complaint is to further the commercial interests of the Complainants and not the interests of consumers in California. If there ever was a circumstance where it was appropriate to unravel the results of prior transmission planning processes despite the dramatic adverse consequences of doing so – a circumstance that the ISO cannot conceive of – the best interests of consumers would dictate the use of updated and current information.**]**

339 Complaint at 27.

Lastly, the ISO notes that the Complainants propose a 90-day limitation on the process for revisiting the ISO's prior evaluation of their proposals and state that, if the process is not concluded by the end of that period, the projects proposed by Complainants should be automatically approved.[340] Again there is no reasonable basis for this presumption – the only purpose it serves is the commercial interests of the Complainants.

For all these reasons and for the reasons set forth above, the remedies requested in the Complaint should be denied.

III. Service and Communications

All service of pleadings and documents and all communications regarding this proceeding should be addressed to the following:

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IV. Attachments

The following documents, in addition to this Answer, support the instant filing:

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340 Complaint at 30.

Attachment A through Attachment MM

Affidavit of Andrew Ulmer

Affidavit of Gary De Shazo

Affidavit of Catalin Micsa

Affidavit of Neil Millar

Affidavit of Ponpranod Didsayabutra

V. Conclusion

For the foregoing reasons, the Commission should deny the Complaint submitted in this proceeding.

Respectfully submitted,

By: *[/s/ Anthony J. Ivancovich]*

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Dated: January 10, 2011

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon each party listed on the official service list for the above-referenced proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California on this 10th day of January, 2011.

/s/ Anna Pascuzzo
Anna Pascuzzo

DECLARATION OF

ANDREW ULMER

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Technology Solutions, LLC and Western Grid Development, LLC, Complainants,	)	
v.	)	**Docket No. EL11-8-000**
California Independent System Operator Corporation, Respondent.	)	

DECLARATION OF ANDREW ULMER

I, Andrew Ulmer, declare as follows:

1. I am an attorney with the California Independent System Operator Corporation. My business address is 151 Blue Ravine Road, Folsom, California 95630. The ISO is a nonprofit public benefit corporation chartered under the laws of the State of California for the purpose of operating and maintaining the reliability of the statewide electric transmission grid for the benefit of the citizens of California. I make this declaration of my own personal knowledge and if called as a witness could and would testify competently thereto.

2. I am informed by co-counsel at the ISO, and believe, that a representative of Transmission Technology Solutions, LLC (TTS), Ms. Jane Luckhardt of the law firm of Downey Brand LLP, contacted the ISO legal department at or near the beginning of March 2009 to inquire about the status of the projects TTS had proposed as part of the ISO's 2009 transmission planning process. During that conversation, my ISO co-counsel directed Ms. Luckhardt to the relevant sections of the ISO tariff regarding the submission of reliability projects by entities that are not participating transmission owners, particularly Section 24.1.2.

3. At or near the beginning of March 2009, representatives of TTS also requested to meet with the ISO concerning the TTS projects. On or about March 12, 2009, I attended a meeting with representatives of TTS at the ISO's offices in Folsom, California. Representatives of TTS physically present at the meeting included Mr. John Dizard and Ms. Jane Luckhardt from the law firm Downey Brand LLP. Counsel from the law firm of Andrews Kurth, LLP, representing TTS, attended the meeting by telephone.

4. At the meeting, TTS provided an overview of its proposed projects. TTS explained that it proposed to install static VAR compensators at various locations on the electric transmission grid under the ISO's operational control. At the meeting, TTS asked the ISO to direct participating transmission owners to enter into good faith negotiations with TTS to lease these static VAR compensators. I told TTS that the ISO did not believe it had authority under its tariff to require a participating transmission owner to enter into negotiations to lease equipment from a particular vendor.

5. On or about April 24, 2009, I telephoned Ms. Jane Luckhardt from the law firm Downey Brand LLP and told her that the ISO intended to issue an amendment to its 2009 transmission plan. I explained that the amendment would address TTS' proposed projects but would state that the ISO does not have authority under its tariff to require a participating transmission owner to enter into negotiations to lease equipment from TTS.

I declare under penalty of perjury that the foregoing is true and correct, except for those matters stated on information and belief, which I believe to be true and correct. Executed on January 7, 2011

Andrew Ulmer

DECLARATION OF

NEIL MILLAR

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Technology Solutions, LLC, and Western Grid Development, LLC, Complainants	)	
v.	)	Docket No. EL11-8-000
California Independent System Operator Corporation, Respondent	)	

DECLARATION OF NEIL MILLAR

I. QUALIFICATIONS AND PURPOSE

Qualifications

1. My name is Neil Millar. I declare that the following is true to the best of my knowledge and belief under penalty of perjury.

2. I am currently employed by the California Independent System Operator Corporation (ISO) as Executive Director, Infrastructure Development. I received a Bachelor of Science in Electrical Engineering degree at the University of Saskatchewan, Canada, and am a registered professional engineer in the province of Alberta.

3. I have been employed for over 28 years in the electricity industry, primarily with a major Canadian investor-owned utility, TransAlta Utilities, and with the Alberta Electric System Operator and its predecessor organizations. Within those organizations, I have held management and executive roles responsible for

preparing, overseeing, and providing testimony for numerous transmission planning and regulatory tariff applications. I have appeared before the Alberta Energy and Utilities Board, the Alberta Utilities Commission, and the British Columbia Utilities Commission.

4. Since November 2010, I have been employed at the ISO, leading the Transmission Planning and Grid Asset departments.

Purpose

5. I have reviewed the economic analysis provided by ZGlobal, specifically the affidavit of Ziad Alaywan, to assess the claims based on the economic analysis performed. This review was necessary as Mr. Alaywan's assessment is relied upon to identify a total net savings purported to be provided by the TTS and WGD proposed projects. The review has led to the identification of a number of errors and flaws, in both the assumptions made by Mr. Alaywan and the economic modeling. The role of economics is but one factor in the transmission planning decision-making process. Setting aside the numerous other concerns that the ISO has with the other overarching issues raised by TTS and WGD, the economic analysis provided by ZGlobal is seriously flawed. A number of individual errors, with examples of the impacts, have been identified and set out in this declaration.

II. ESTIMATING PG&E'S INCREMENTAL O&M AND A&G COSTS

6. Mr. Alaywan has estimated an O&M and A&G rate for PG&E based on PG&E's total O&M and A&G costs and dividing those costs by gross plant.[1] This rate is then applied against total new capital costs associated with PG&E projects, in contrast to the purely incremental rate he estimates for his clients.

7. First, the determination of the rate is flawed in several ways. Each of those flaws must be examined in order.

8. Mr. Alaywan includes all of PG&E's O&M and A&G costs in determining an incremental rate, which in itself is an error. Rather than compound the speculation as to the more appropriate delineation of fixed versus variable cost structure, the ISO will leave the more correct delineation of incremental versus average costs to others to address. However, even with the data Mr. Alaywan referenced in his own affidavit, other obvious assumption errors can be highlighted.

9. Mr. Alaywan has applied his calculated O&M and A&G rates to all new capital costs incurred in PG&E projects based on capital cost.

10. Applying additional incremental O&M and A&G costs to replacement projects such as re-conductoring and to transformer replacements is counter-intuitive. PG&E would have been tasked with operating and maintenance costs on the existing equipment regardless of whether re-conductoring or transformer

[1] Paragraph 48, Affidavit of Mr. Alaywan.

replacement took place, and arguably the incremental costs would be lower, not higher, at least in the initial years with new equipment replacing older equipment. For example, projects such as the alternative to the WGD Guernsey project involving transformer replacement, and the alternative to the TTS Old River project involving re-conductoring the Kern-Old River 70 kV lines result in additional capital costs, but do not increase the number of facilities needing to be maintained.

11. Setting those issues aside, and if one truly had valid incremental costs for PG&E, applying those costs on the basis of gross plant (reflecting year of construction) is also flawed. By applying incremental rates based on gross plant without making any attempt to adjust for inflation on the original construction costs, Mr. Alaywan has implicitly assumed that a new transmission line requires more maintenance today than an older transmission line of equal length and configuration, simply because the capital cost of the new line has increased due to inflation relative to the old line.

12. With the information and assumptions relied upon by Mr. Alaywan for PG&E (gross plant of $5,404 million, inflation of 2.25%, service life of 40 years) and by assuming that PG&E has built an equal amount of facilities in each year, I have adjusted for inflation and determined an equivalent value of gross plant in 2010 dollars as set out in Appendix A.4. While this does not address the other assumption errors, it does indicate that correcting for this issue alone, Mr. Alaywan's calculation of the O&M and A&G rate for PG&E is approximately 50% too high for this reason alone.

13. While this analysis only examines the effect of one of the errors identified, it does highlight the weaknesses in the analysis Mr. Alaywan undertook. As O&M and A&G rates are included in all project evaluations performed by Mr. Alaywan, all of the economic evaluations presented in his affidavit are impacted by this flaw, and to a greater or lesser extent depending on the specific capital cost details.

III. ECONOMIC ANALYSIS

14. Mr. Alaywan's analysis consisted of determining an annual revenue requirement (which would be recovered from ratepayers in each year) for each project, and then applying a discount rate to reach revenue stream to determine the net present value. Numerous errors in modeling have been made that materially affect his results; I will explore each of these in turn.

- Not properly accounting for different service lives in comparing net present values ("NPV") of revenue requirements,
- Using different discount rates in assessing the NPV of competing projects from the customer perspective, and
- Not applying inflation to capital projects when deferring them or staging them.

Consistency of Period of Net Present Value

15. Mr. Alaywan's analysis is flawed in failing to properly address the different service lives of projects in his determination of NPVs.

16. As noted by Mr. Alaywan, he determined the NPV of the calculated annual revenue requirements "for the service life of each project."[2] In making a simple comparison of net present values of different service lives, he considered the costs, but not the benefits of extra years of service. For example, two projects with identical annual revenue requirements in each year of service, but with two different service lives would yield different net present values simply due to the extra years of service, and associated costs.

17. Proper consideration of these end-of-period effects can be provided by a number of means such as by assuming that the longer-lived project is salvaged (with an accounting of salvage costs and salvaged material), by assuming the shorter-lived project is replaced at the end of its first service life and performing an NPV over the life of the longer-lived project, or truncating the analysis for both projects to the shorter of the two service lives.

18. For comparative purposes, I have provided a comparison of the latter method in Appendix A.1, comparing the PG&E Atlantic Placer Project with the WGD Auburn Project. Calculating the net present value of both the PG&E project and the WGD project over a consistent 25 year period reduces the benefits claimed by Mr. Alaywan by over 16%. As inconsistent study periods are employed in all of Mr. Alaywan's economic evaluations, all of the economic evaluations presented in his affidavit are impacted by this flaw, and to a greater or lesser extent depending on the specific capital cost details.

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[2] Paragraph 39, Affidavit of Ziad Alaywan.

Consistency in Application of Discount Rates

19. Mr. Alaywan's analysis is flawed in failing to properly apply consistent discount rates in calculating net present values of competing projects' annual revenue requirements.

20. Mr. Alaywan's analysis determined annual revenue requirements for comparative purposes by applying each project sponsor's Rate of Return (ROR) in determining an annual revenue requirement (which would be recovered from ratepayers in each year) for each project, and then applying a discount rate to reach revenue stream to determine the net present value. Erroneously, however, he applied the ROR of each project sponsor to the annual revenue requirement of that sponsor's project.

21. As the discount rate is meant to determine the net present value ratepayers would attribute to the annualized costs, a consistent discount rate based on how ratepayers view the present value of a future expenditure must be applied.

22. For comparative purposes, I have calculated the net present value of the two annual revenue requirement streams calculated by Mr. Alaywan (in Appendix A.2), comparing the PG&E Atlantic Placer Project with the WGD Auburn Project, using the WGD ROR as the discount rate for both revenue requirement streams.

23. Correcting this error results in a 15.5% reduction in the benefits claimed by Mr. Alaywan for the WGD Auburn project.

24. Further compounding the fallacy of applying different discount rates becomes apparent in reviewing the TTS Old River project, which I reviewed in more detail to address concerns with Mr. Alaywan's inflation rates as later in this affidavit.

25. In this example, Mr. Alaywan compared the annual revenue requirement of the PG&E Kern-Old River Project to the annual revenue requirement of the TTS Old River Interim Solution (for 10 years) followed by the more permanent PG&E project being deferred by 10 years.

26. Mr. Alaywan applied the lower PG&E ROR as the discount rate to the Kern-Old River Project proposed by PG&E. He appears to have applied the much higher TTS ROR (which produces a lower net present value of costs for a given cost or revenue stream) to both the TTS annual revenue requirement for the first 10 years and the PG&E annual requirement for the PG&E project beyond the initial 10 years. This mixing of apples and oranges over-inflates the perceived benefits of Mr. Alaywan's clients' projects.

27. As inconsistent discount rates are employed in all of Mr. Alaywan's economic evaluations, all of the economic evaluations presented in his affidavit are impacted by this flaw, and to a greater or lesser extent depending on the specific capital cost details.

<u>Inconsistencies in Application of Inflation Rates</u>

28. Mr. Alaywan's analysis is inconsistent in applying inflation to costs, resulting in an overstatement of benefits of WGD and TTS projects.

29. Mr. Alaywan applied an inflation rate of 2.25% to his estimated O&M and G&A costs in determining annual revenue requirements while estimating lower incremental O&M and A&G rates for TTS and WGD projects. Assuming WGD and TTS O&M and A&G rates are in fact lower than PG&E's, including the impacts of inflation results in higher costs being attributed to the PG&E projects.

30. However, in a number of cases inflation has been ignored. Specifically, when a TTS project is believed to enable the deferral of a PG&E project, the effects of inflation on the deferred construction of the PG&E project has not been taken into account. This error results in over-estimating the benefits of deferring a capital project.

31. In the case of WGD projects that are staged over time, the effects of inflation have not been added in to reflect the higher future cost of construction of later stages. This omission results in an erroneously low net present value for those projects compared to the PG&E alternatives.

32. As set out in Appendix A.3, I have calculated the impact of this correction on the economic evaluation of the TTS Old River proposal. This single correction erodes over 35% of the economic benefit claimed by Mr. Alaywan for this project.

33. Besides the TTS Old River analysis, failing to include inflation in the capital cost of deferred projects impacts the TTS Watsonville analysis as well as the WGD Coppermine, WGD Guernsey, WGD Weedpatch, WGD Stockton and WGD Madison analyses. The impact for each of these varies to a greater or lesser extent depending on the specific capital cost details.

Referring to Other Benefits

34. Mr. Alaywan cites a number of other benefits associated with his clients' proposed project, and is selective as to which benefits he has explored. While estimates are provided regarding certain potential benefits, the impact on other potential benefits, such as transmission line loss impacts, are not explored. As many of the PG&E projects involved additional conductor, either in for the form of new transmission lines or re-conductoring, these projects would expect to be much more effective at reducing transmission line losses than additional voltage support through reactive power sources proposed by TTS. The inconsistent consideration of benefits also detracts from the usefulness of Mr. Alaywan's economic analysis.

I hereby declare that the foregoing is true to the best of my knowledge and belief under penalty of perjury. Executed on Jan 10, 2011.

Neil Millar

Appendix A.1 to Millar Affidavit

Adjustment to Align Service Lives

Comparison of WGD- Auburn Project and PG&E Atlantic Placer Project

Discount Rates Employed:

PG&E ROR	9.268%	Sum of Line 74, 75 and 76 Column D, Page 5 of 33, Attachment A, Alaywan Affidavit
WGD ROR	10.000%	Sum of Line 74, 75 and 76 Column B, Page 5 of 33, Attachment A, Alaywan Affidavit

	PG&E Annual Revenue Requirement (1)			WGD Annual Revenue Requirement (2)		
1	$ 12,539,639			$ 9,577,402		
2	$ 12,227,264			$ 9,216,967		
3	$ 12,099,254			$ 8,996,870		
4	$ 11,969,158			$ 8,774,785		
5	$ 11,837,677			$ 8,551,236		
6	$ 11,705,176			$ 8,326,494		
7	$ 11,561,605			$ 8,092,878		
8	$ 11,408,338			$ 7,851,427		
9	$ 11,256,160			$ 7,610,364		
10	$ 11,106,110			$ 7,370,471		
11	$ 10,956,877			$ 7,130,737		
12	$ 10,809,838			$ 6,892,205		
13	$ 10,663,684			$ 6,653,863		
14	$ 10,519,793			$ 6,416,752		
15	$ 10,376,858			$ 6,179,864		
16	$ 10,335,378			$ 6,019,899		
17	$ 10,295,263			$ 5,860,447		
18	$ 10,157,770			$ 5,626,122		
19	$ 10,022,055			$ 5,392,600		
20	$ 9,888,158			$ 5,159,900		
21	$ 9,756,122			$ 4,928,041		
22	$ 9,625,988			$ 4,697,041		
23	$ 9,497,798			$ 4,466,919		
24	$ 9,371,596	25 Years of Service		$ 4,237,695	25 Years of Service	
25	$ 9,247,427	(a) with PG&E ROR	$108,997,150	$ 4,009,390	(c) with WGD ROR	$70,435,568
26	$ 9,125,337					
27	$ 9,005,373					
28	$ 8,887,581					

29	$	8,772,012				
30	$	8,658,716				
31	$	8,547,742				
32	$	8,439,145				
33	$	8,332,976				
34	$	8,229,291				
35	$	8,128,145				
36	$	8,029,597				
37	$	7,933,703				
38	$	7,840,525				
39	$	7,750,122	40 Years of Service			
40	$	7,662,558	(b)	with PG&E ROR	$116,375,097	See Note 3

Percent reduction in savings:

(d)	Alaywan method	= (b - c)	$45,939,528
(e)	Adjustment	= (a - c)	$7,377,946
	Percent reduction in benefits	= (e / d)	16.1%

Notes:

Note 1	Alaywan Affidavit Appendix A - WGD Cost Comparison Page 7 of 33 Column M
Note 2	Alaywan Affidavit Appendix A - WGD Cost Comparison Page 6 of 33 Column M
Note 3	Value determined Alaywan Affidavit is $116,373,032. We are unable to account for the difference of $2,065

Appendix A.2 to Millar Affidavit
Adjustment to Discount Rates
Comparison of WGD- Auburn Project and PG&E Atlantic Placer Project

Discount Rates Employed:

PG&E ROR	9.268%	Sum of Line 74, 75 and 76 Column D, Page 5 of 33, Attachment A, Alaywan Affidavit
WGD ROR	10.000%	Sum of Line 74, 75 and 76 Column B, Page 5 of 33, Attachment A, Alaywan Affidavit

	PG&E Annual Revenue Requirement (1)	WGD Annual Revenue Requirement (2)		
1	$ 12,539,639	$ 9,577,402		
2	$ 12,227,264	$ 9,216,967		
3	$ 12,099,254	$ 8,996,870		
4	$ 11,969,158	$ 8,774,785		
5	$ 11,837,677	$ 8,551,236		
6	$ 11,705,176	$ 8,326,494		
7	$ 11,561,605	$ 8,092,878		
8	$ 11,408,338	$ 7,851,427		
9	$ 11,256,160	$ 7,610,364		
10	$ 11,106,110	$ 7,370,471		
11	$ 10,956,877	$ 7,130,737		
12	$ 10,809,838	$ 6,892,205		
13	$ 10,663,684	$ 6,653,863		
14	$ 10,519,793	$ 6,416,752		
15	$ 10,376,858	$ 6,179,864		
16	$ 10,335,378	$ 6,019,899		
17	$ 10,295,263	$ 5,860,447		
18	$ 10,157,770	$ 5,626,122		
19	$ 10,022,055	$ 5,392,600		
20	$ 9,888,158	$ 5,159,900		
21	$ 9,756,122	$ 4,928,041		
22	$ 9,625,988	$ 4,697,041		
23	$ 9,497,798	$ 4,466,919		
24	$ 9,371,596	$ 4,237,695	25 Years of Service	
25	$ 9,247,427	$ 4,009,390	(c) with WGD ROR	$70,435,568
26	$ 9,125,337			
27	$ 9,005,373			
28	$ 8,887,581			

29	$	8,772,012
30	$	8,658,716
31	$	8,547,742
32	$	8,439,145
33	$	8,332,976
34	$	8,229,291
35	$	8,128,145
36	$	8,029,597
37	$	7,933,703
38	$	7,840,525
39	$	7,750,122
40	$	7,662,558

40 Years of Service

(b)	with PG&E ROR	$116,375,097	See Note 3
(a)	with WGD ROR	$109,248,017	

Percent reduction in savings:

(d)	Alaywan method	= (b - c)	$45,939,528
(e)	Adjustment	= (b - a)	$7,127,080
	Percent reduction in benefits	= (e / d)	15.5%

Notes:

Note 1 Alaywan Affidavit Appendix A - WGD Cost Comparison Page 7 of 33 Column M

Note 2 Alaywan Affidavit Appendix A - WGD Cost Comparison Page 6 of 33 Column M

Note 3 Value determined Alaywan Affidavit is $116,373,032. We are unable to account for the difference of $2,065

Appendix A.3 to Millar Affidavit
Application of Inflation to Staged Projects Deferred Capital Expenditures
Comparison of TTS Old River Project (followed by PG&E Project) and PG&E Kern-Old River Project

Discount Rates Employed:

PG&E ROR	9.268%	Sum of Line 33, 34, and 35, Column D, Page 2 of 6, Attachment B, Alaywan Affidavit
TTS ROR	10.000%	Sum of Line 33, 34, and 35, Column B, Page 2 of 6, Attachment B, Alaywan Affidavit
Assumed annual inflation rate	2.25%	Mr. Alaywan Affidavit, Page 21, Paragraph 45

	PG&E Annual Revenue Requirement (1)			TTS Annual Revenue Requirement (2)	TTS Annual Revenue Requirement Adjusted	
1	$ 4,496,679			$ 2,538,357	$ 2,538,357	
2	$ 4,349,243			$ 2,430,141	$ 2,430,141	
3	$ 4,263,262			$ 2,357,413	$ 2,357,413	
4	$ 4,176,585			$ 2,284,181	$ 2,284,181	
5	$ 4,089,447			$ 2,210,580	$ 2,210,580	
6	$ 4,001,968			$ 2,136,677	$ 2,136,677	
7	$ 3,910,800			$ 2,060,530	$ 2,060,530	
8	$ 3,816,400			$ 1,982,402	$ 1,982,402	
9	$ 3,722,363			$ 1,904,372	$ 1,904,372	
10	$ 3,629,034			$ 1,826,637	$ 1,826,637	
11	$ 3,535,979			$ 4,496,679	$ 5,617,267	Application of Inflation
12	$ 3,443,654			$ 4,349,243	$ 5,433,089	
13	$ 3,351,625			$ 4,263,262	$ 5,325,681	
14	$ 3,260,350			$ 4,176,585	$ 5,217,404	
15	$ 3,169,394			$ 4,089,447	$ 5,108,551	
16	$ 3,112,256			$ 4,001,968	$ 4,999,272	
17	$ 3,055,573			$ 3,910,800	$ 4,885,385	
18	$ 2,966,430			$ 3,816,400	$ 4,767,460	
19	$ 2,877,880			$ 3,722,363	$ 4,649,989	
20	$ 2,789,937			$ 3,629,034	$ 4,533,402	
21	$ 2,702,614			$ 3,535,979	$ 4,417,157	
22	$ 2,615,924			$ 3,443,654	$ 4,301,824	
23	$ 2,529,883			$ 3,351,625	$ 4,186,861	
24	$ 2,444,504	25 Years of Service		$ 3,260,350	$ 4,072,840	
25	$ 2,359,803	(b) with PG&E ROR	$36,159,592	$ 3,169,394	$ 3,959,218	
				$ 3,112,256	$ 3,887,841	
				$ 3,055,573	$ 3,817,032	
				$ 2,966,430	$ 3,705,675	
				$ 2,877,880	$ 3,595,058	
				$ 2,789,937	$ 3,485,199	

			$ 2,702,614		$ 3,376,115
			$ 2,615,924		$ 3,267,821
			$ 2,529,883		$ 3,160,339
			$ 2,444,504		$ 3,053,683
			$ 2,359,803		$ 2,947,874
35 Years of Service					
(c)	with TTS ROR		$26,967,962	(a)	$30,269,392

Reduction in Benefits:

(d)	Alaywan method	= (b - c)	$9,191,630
(e)	Adjustment	= (a - c)	$3,301,430
	Percent reduction in benefits	= (e / d)	35.9%

Notes:

Note 1 Alaywan Affidavit Appendix B - TTS Cost Comparison Page 4 of 6 Column M

Note 2 Alaywan Affidavit Appendix B - TTS Cost Comparison Page 3 of 6 Column M

Appendix A.4 to Millar Affidavit

Calculation of Equivalent Gross Plant in 2010 Dollars
(PG&E Estimated Gross Plant in As Spent Dollars)

Assumed inflation rate		2.25%		Mr. Alaywan Affidavit, Page 21, Paragraph 45
Assumed service life		40	Years	Mr. Alaywan Affidavit, Attachment A, Page 4 of 33
PG&E O&M	(c)	$154	Million	Mr. Alaywan Affidavit, Page 21, Paragraph 48
PG&E A&G	(d)	$63	Million	Mr. Alaywan Affidavit, Page 21, Paragraph 48
Gross Plant		$5,454	Billion	Mr. Alaywan Affidavit, Page 21, Paragraph 48

Adjusted Gross Plant divided by Nominal Gross Plant	**149.3%**	= b / a
Estimated O&M and A&G rate ignoring inflation	4.0%	= (c + d) / a
Estimated O&M and A&G rate considering inflation	2.7%	= (c + d) / b
Overstatement of O&M and A&G Rate	149.3%	

	Year	Inverse of Inflation Factor	PG&E Gross Plant: Estimated Nominal Dollars		PG&E Gross Plant: Adjusted to 2010 Dollars
Total:		26.783	(a) $ 5,454	(b)	$ 8,146
	1	1.000	$ 204		$ 204
	2	0.978	$ 199		$ 204
	3	0.956	$ 195		$ 204
	4	0.935	$ 190		$ 204
	5	0.915	$ 186		$ 204
	6	0.895	$ 182		$ 204
	7	0.875	$ 178		$ 204
	8	0.856	$ 174		$ 204
	9	0.837	$ 170		$ 204
	10	0.819	$ 167		$ 204
	11	0.801	$ 163		$ 204
	12	0.783	$ 159		$ 204
	13	0.766	$ 156		$ 204
	14	0.749	$ 152		$ 204
	15	0.732	$ 149		$ 204
	16	0.716	$ 146		$ 204
	17	0.700	$ 143		$ 204
	18	0.685	$ 140		$ 204
	19	0.670	$ 136		$ 204
	20	0.655	$ 133		$ 204
	21	0.641	$ 130		$ 204
	22	0.627	$ 128		$ 204
	23	0.613	$ 125		$ 204
	24	0.599	$ 122		$ 204
	25	0.586	$ 119		$ 204
	26	0.573	$ 117		$ 204
	27	0.561	$ 114		$ 204
	28	0.548	$ 112		$ 204
	29	0.536	$ 109		$ 204
	30	0.525	$ 107		$ 204
	31	0.513	$ 104		$ 204
	32	0.502	$ 102		$ 204
	33	0.491	$ 100		$ 204
	34	0.480	$ 98		$ 204

35	0.469	$	96	$	204
36	0.459	$	93	$	204
37	0.449	$	91	$	204
38	0.439	$	89	$	204
39	0.429	$	87	$	204
40	0.420	$	86	$	204

DECLARATION OF

GARY DESHAZO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Technology Solutions, LLC, and Western Grid Development, LLC, Complainants	)	
v.	)	Docket No. EL11-8-000
California Independent System Operator Corporation, Respondent	)	

DECLARATION OF GARY L. DESHAZO

I, Gary L. DeShazo, declare as follows:

I. QUALIFICATIONS

1. My name is Gary L. DeShazo. I am currently employed by the California Independent System Operator Corporation (ISO) as Director, Regional Transmission North. I received a Bachelor of Science in Electrical Engineering degree and a Master of Science in Electrical Engineering degree at New Mexico State University in Las Cruces, New Mexico.

2. I have been employed for over 30 years in the electric utility industry, primarily with a major municipal utility, Salt River Project, and with the ISO for over nine years. Within those organizations, I have held engineering and management roles responsible for analyzing, developing, overseeing the development of, and

presenting both transmission projects and ten-year transmission plans to executive management and regulatory bodies in California.

II. PURPOSE OF DECLARATION

3. My declaration has three purposes. First, I will describe the meetings that I attended with representatives from Transmission Technologies Solutions, LLC (TTS) during 2008 and 2009. Next, I will describe the content of presentations that I made to the ISO Board of Governors on March 27, 2009 and to the stakeholders attending the 2010 draft unified study assumptions and study plan meeting held on March 24, 2009. Finally, I will describe the intent of the amendment to the 2009 Transmission Plan.

III. MEETINGS WITH TTS

4. Between June 1, 2008 and August 1, 2009, three meetings were held at the ISO which included representatives from the ISO and TTS. The following provides, to the best of my knowledge, who attended those meetings and a brief summary of the information discussed at those meetings.

Meeting: June 19, 2008

5. On June 19, 2008, I attended a meeting held at the ISO. Jenny Mueller, representing TTS, requested the meeting on behalf of her client who was proposing to submit projects into the ISO's request window to install FACTS devices at multiple locations in the PG&E system. TTS provided a written report which was included as an attachment in the meeting notice sent to all ISO attendees. Several other engineers from my staff were also in attendance at this

meeting. At paragraph 11 of her affidavit, Ms. Mueller has stated that legal personnel from the ISO were in attendance at that meeting. However, there were no ISO legal representatives at the meeting; engineers from my staff and I were the only ISO representatives in attendance.

Meeting: December 15, 2008

6. On December 15, 2008, I attended a meeting held at the ISO. Armando Perez, representing TTS, requested the meeting on behalf of his client. Others in attendance at the meeting included John Dizard, TTS Chief Executive Officer, Laura Manz, ISO Vice President of Market & Infrastructure Planning, and me. I do not recall Ms. Mueller attending this meeting.

7. During this meeting Mr. Dizard provided an overview briefing of TTS and its objective to provide a leasing opportunity of static VAR compensators for the ISO to consider when assessing solutions to reliability concerns for the ISO's controlled grid. While some technical highlights were presented, the briefing was predominately informational in nature. At paragraph 15 of her affidavit, Ms. Mueller has stated that the meeting was scheduled with the ISO's "legal team," but there were no ISO legal representatives at that meeting.

Meeting: July 23, 2009

8. On July 23, 2009, I attended a meeting held at the ISO. Mr. Perez, representing TTS, requested the meeting on behalf of his client. Judith Sanders, Senior Counsel in the ISO Legal Department, was also in attendance. The primary purpose of this meeting was to answer questions posed by TTS about the amended 2009 Transmission Plan and the disposition of the TTS projects. At the

meeting, Ms. Sanders advised Mr. Perez, consistent with the discussion in the plan, that the ISO did not have tariff authority to direct Participating TOs (PTOs) to enter into equipment leasing arrangements with specific vendors.

IV. PRESENTATIONS TO THE ISO GOVERNING BOARD AND STAKEHOLDERS

9. On March 27, 2009, the ISO Board of Governors held its regularly scheduled meeting. During that meeting, I presented the 2009 Transmission Plan to the Board for informational purposes only; no formal action from our Board was requested. Such an "informational" presentation is made to our Board each year. During the presentation, I generally described the planning process; how the process had worked during that planning cycle; a high level of the work completed; and a summary of the Request Window results. I informed the Board that there were 33 projects still being evaluated by ISO staff either because some additional analysis was needed to finalize staff's recommendations to management or because insufficient information had been provided to the ISO by the project proponent for ISO staff to appropriately assess the project proposal. Those projects addressed by Ms. Mueller in her affidavit were included in those 33 projects.

10. On March 24, 2009, at the stakeholder meeting convened to discuss the 2010 unified planning assumptions and study plan. I informed stakeholders that there were 33 projects still being evaluated by the ISO staff and that the ISO intended to continue its assessment of these proposals as "ongoing" or "requiring further information." I told stakeholders that the ISO intended to amend the final 2009 Transmission Plan to incorporate the results of these continued assessments.

V. THE INTENT OF THE 2009 TRANSMISSION PLAN AMENDMENT

11. As I advised stakeholders at the March 24, 2009 meeting, the reason that the ISO amended the 2009 Transmission Plan was to bring the 2009 planning cycle to closure by completing the staff evaluation of certain projects for which additional information or evaluation was needed. This evaluation included the TTS proposals and the long-term solutions that the Participating TOs had submitted through the request window in response to the reliability concerns for which the TTS proposals had been submitted as interim solutions.

12. With respect to the TTS proposals, the intent of the amendment was to notify stakeholders, the PTOs, and TTS that: (1) the ISO did not have the tariff authority to direct the PTOs to enter into leasing arrangements with TTS; (2) the long-term PTO solutions for the reliability concerns had been approved by management and could move forward; and (3) the PTOs should be on notice that the "gaps" between the forecasted dates of the reliability concerns and the in-service dates of the permanent solutions needed to be addressed and that leasing static VAR compensator equipment was one available option.

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

Gary L. DeShazo

DECLARATION OF

CATALIN MICSA

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Technology Solutions, LLC, and Western Grid Development, LLC, Complainants	)	
v.	)	Docket No. EL11-____-000
California Independent System Operator Corporation, Respondent	)	

DECLARATION OF CATALIN MICSA
IN SUPPORT OF
CALIFORNIA INDEPENDENT SYSTEM OPERATOR, INC.

I. QUALIFICATIONS AND PURPOSE

1. My name is Catalin Micsa. I am currently employed by California Independent System Operator Corporation (ISO) as senior transmission planning engineer. I received a Bachelor of Science in Electrical Engineering degree at Electro-technical Faculty Timisoara, Romania, and a Master of Science in Electrical Engineering at California State University, Sacramento.

2. I have been employed at the ISO for over 11 years. I am responsible, among other things, for conducting reliability assessment studies to ensure that the ISO grid is planned within the NERC and WECC Reliability Criteria as well as ISO Grid Planning Standards and evaluating solutions to address identified reliability contingencies.

3. The purpose of my affidavit is to respond to claims set forth in the affidavits of Jenny Mueller and Ziad Alaywan that the ISO erred in rejecting certain reliability-driven transmission solutions submitted by Transmission Technology Solutions, LLC ("TTS") and Western Grid Development, LLC ("WGD") in the 2009 and 2010 Transmission Plans.

II. GENERAL ITEMS REGARDING TTS AND WGD CLAIMS

4. Ms. Muller alleges (page 7, item 25) that the ISO has deviated from the initial planning assumptions between posting preliminary results and releasing the final results and plan, referring to, among other things, corrections made to system data. Not only is this permitted under the ISO tariff when documented by the ISO, it is a necessary feature of any planning process to ensure that planning decisions are based on the most up-to-date information, data, line ratings, and configurations available. Otherwise, the ISO could be making incorrect planning decisions or decisions that do not result in the most cost-effective solutions being pursued based solely as the result of relying on outdated information, even though more current information was available.

The ISO prepared and presented the Preliminary Results based on the reliability assessment base cases posted on the ISO web site and based on the generally agreed upon planning assumptions. Data errors and updates to data were uncovered through the validation, review, stakeholder input, and approval process after the publication of study results. Those updates and corrections are the result of detailed model validation and research done during the project approval phase, including developing the final study results, as well as reflecting updates from maintenance activities by PTOs. These updates can include, among other things, the results of maintenance activities performed by PTOs as well as re-rating of transmission lines through field validation of transmission line clearances, *etc.* All of the so-called updates at issue that the ISO relied on were documented by the ISO in the planning processes and were reflected in the final study results and transmission plan.

III. DISCUSSION OF ALLEGATIONS PERTAINING TO SPECIFIC TTSAND WGD PROJECTS

A. TTS's Trinity Interim Solution

5. Ms. Mueller claims in her affidavit (page 19, paragraph 63) that TTS has submitted this project in order to meet identified voltage concerns in this area beginning in 2009. This is not correct. As shown in the TTS request window submission form for the Trinity Interim Solution (page 2) the proposed in service date for TTS's project was October, 2010, not 2009, and TTS proposed a five-year lease with PG&E. Thus, at best, the TTS project could only help meet identified voltage concerns after October, 2010. In the amended 2009 Transmission Plan, at page 302, the ISO suggested that the TTS proposal could provide an interim solution for the interim period before the agreement between PG&E and Trinity PUD was formalized. Based on the October, 2010, in service date, the TTS

proposal would have been available as an interim solution only if the negotiations had not been finalized by that date.

6. At the time of the 2009 planning process, PG&E and Trinity PUD were negotiating to transfer Trinity PUD's load out of the PG&E Service Territory. This would result in the Trinity PUD load leaving the ISO Balancing Authority Area and no longer being served by PG&E's facilities that are part of the ISO-Controlled Grid. The effect of the Trinity PUD load leaving the ISO Controlled Grid would be that the identified transmission overloads would no longer exist. The ISO included information in both the 2009 Transmission Plan[1] and the 2010 Transmission Plan[2] describing the Trinity area reconfiguration as a project being undertaken by the Western Area Power Administration (WAPA) project in an adjacent control area that would result in the Trinity PUD load being served by WAPA and not PG&E, thereby eliminating any reliability concerns in the area because the load would no longer be served by the PG&E facilities. Because this was a WAPA project that was not part of the ISO Controlled Grid, it did not require ISO approval. Also, it was not modeled in the previous expansion plan cases because it was not included in the WECC base cases by the neighboring control area. Based on information the ISO received from the parties directly involved in the load transfer, the ISO anticipated that the

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[1] See page 81 of the plan at: http://www.caiso.com/2354/2354f34634870.pdf.

[2] See page 80 of the plan at: http://www.caiso.com/2771/2771e57239960.pdf.

Trinity PUD load to "leave" the ISO Balancing Authority Area and no longer be served off of the ISO Controlled Grid by April 1, 2010.[3] WAPA actually placed the Trinity area reconfiguration in service and the Trinity PUD load was no longer served by PG&E starting in May 2010, approximately a month later than expected. Thus, all reliability concerns in the area were eliminated by the transfer of load, as the ISO had expected. Specifically, WAPA's project resulted in all loads in the area – Mill Station (Weaverville), Douglas City and Hayfork – being removed from the ISO grid and into the neighboring control area without any normally closed ties between the ISO control area and the neighboring control area in this vicinity. Because TTS's request window submission proposed an in-service date of October 2010 for the five-year lease of SVC equipment to PG&E, there was no need for the TTS project because the reliability performance concern was expected to be – and in fact was – resolved prior to the proposed in service date of the TTS solution. Since all loads have been removed from the ISO Balancing Authority Area, there are no more reliability concerns in the area (see the new 2010 ISO Reliability Assessment: Preliminary Study Results at: http://www.caiso.com/280d/280dc32b51b0.pdf.)

B. WGD's Auburn 60 kV Energy Storage Project

[3] For example, in the 2010 Transmission Plan (p. 80), the ISO noted that it expected this to occur in April of 2010.

7. Ms. Mueller states in paragraph 91 of her affidavit that that WGD submitted a project to resolve the normal (Category A) thermal overload of the Placer 115/60 kV transformer and other thermal overloads, as identified by the ISO's September 17, 2009 Reliability Assessment. She claims that the ISO rejected the Auburn Energy Storage Project. In paragraph 85 of her affidavit, Ms. Mueller asserts that the ISO's rejection of the battery storage project is technically flawed because the ISO rejected the project before performing the necessary power flow analysis to determine that the project could be a component of the long-term plan; and (2) the project was rejected prior to the ISO performing the necessary economic analysis to determine if the project was the least cost alternative.

8. Although Ms. Mueller claims that the Auburn 60 kV Energy Storage Project was submitted to address other thermal overloads in the area, WGD's request window submission indicates that WGD submitted the project to address the overloads at the Placer 115/60 kV transformer bank. (WGD's request window submission form at 1-2, 8). WGD did not identify any other reliability problems that the storage battery project was intended to address.

9. Contrary to Ms. Mueller's claims and as made clear in the final 2010 Transmission Plan (page 111), the ISO did not reject the proposed Auburn

battery storage project. The ISO stated that it "will evaluate the battery storage project to determine whether PG&E should be directed to install such facility to address reliability needs in the area." The ISO further stated that it "will consider the [PG&E] Atlantic-Placer voltage upgrade and the Auburn battery storage project, along with other possible options in the next ISO planning cycle to determine what facilities PG&E should be required to construct to meet the reliability needs in the area." Thus, the ISO did not reject a possible battery storage solution to the reliability needs in the area. However, the ISO pointed out that under its Tariff, the Participating Transmission Owner with a PTO Service Territory in which any transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance, and maintain the upgrade or addition.

10. The ISO also explained in a May 5, 2010 letter sent to WGD that the ISO has not yet approved a project(s) to meet the myriad of reliability needs in this area. The Placer area is very complex with both peak and off-peak transmission constraints. As such, it requires a comprehensive long-term solution that solves all of the constraints, not a solution that addresses only one or small part of these constraints. PG&E's Atlantic-Placer Voltage Conversion project solves fifteen peak reliability problems in the area (see pages 88-110 tables 3-3.4.6 through 3-3.4.9 where ISO solution is titled "Upgrade Atlantic-Placer corridor to 115 kV operation" – 3 in page 88, 2 in page 91, 5 in page 103, 3 in page 104 and 2 in page 108, in the

2010 ISO Transmission Plan

http://www.caiso.com/2771/2771e57239960.pdf) along with other off peak problems driven by hydro and import patterns. TTS's Auburn 60 kV Energy Storage project in its submission form was proposed to deal with only two reliability problems (see page 88 under overloaded facility "Placer 115/60 kV"), after ISO review this project could potentially help mitigate or reduce the reliability problems for a total of ten problems as explained under PG&E's Atlantic-Placer Voltage Conversion above except for 5 item in page 103.

11. Because a battery has the potential to be a net load at times (it needs to charge more than it can discharge), the question arises whether the proposed battery can charge enough in order to mitigate any peak reliability concerns because there are numerous off-peak reliability concerns in this area. The power flows in and through this area are driven not only by load levels, but also by hydro generation output and the Drum-Summit intertie flows. Due to these factors, the operation of this system is extremely dynamic with multiple constraints that need to be mitigated throughout the day. It is not clear, at this time, whether the battery storage resource can charge enough throughout the daily cycle in order to help mitigate the binding constraints in the area throughout the day. For the reasons specified above, this area is one of the worst areas on the ISO Controlled Grid to add load even during off-peak hours. While PG&E's project adds transmission capacity to the grid and reduces potential

congestion in all hours of the year, WGD's proposal may potentially mitigate only some congestion issues during some hours, but exacerbate existing congestion during different hours. The ISO does not consider the battery project as a comprehensive long-term solution given the large number of reliability problems in this area; however, the ISO will further assess the Atlantic - Placer Voltage Conversion project along with other possible options (including battery storage) in future planning cycles.

C. WGD's Coppermine 70 kV Energy Storage Project

12. Ms. Mueller states that WGD submitted the Coppermine Energy 70 kV Storage Project to address single outage (Category B) thermal overload and voltage overload in the Coppermine area. She also notes that the ISO indicated that there was no need for WGD's storage project because PG&E previously had undertaken the Tivy Valley-Reedley maintenance project which reduced the single contingency (Category B) overload to extreme events (Category D). Ms. Mueller notes that the 2008 Transmission Plan identified the maintenance project in the study assumption list, and the 2008 Transmission Plan is used as input for modeling the transmission system for the 2009 Transmission Plan. She questions why the results of the 2009 Transmission Plan showed an overload even though if should have reflected the impact of the Tivy-Valley-Reedley maintenance project in the assumptions.

13. WGD's request window submission for the Coppermine 70 kV storage project (at page 2) indicates that WGD submitted the project based on its

review of PG&E's 2009 Electric Transmission Grid Expansion Plan which indicated that for summer peak conditions an outage of the Borden-Coppermine 70 kV line when Friant generation is offline will cause low voltage in the Coppermine area. WGD based its request window submission on outdated information. The ISO's 2010 Transmission Plan Reliability Assessment study results did not identify the Category B contingency that the Coppermine 70 kV storage project was intended to address, *i.e.*, an outage of the Coppermine-Borden 70 kV line, while Friant generation is offline. Pages 39-45 of the Reliability Assessment pertaining to the Greater Fresno local area show no overloads or voltage problems resulting from an outage on the Borden-Coppermine line, when Friant generation is off line.

14. There was no reliability need for any project during the 2010 Transmission Plan cycle because the Category B low voltage problem and overloads that had previously been identified in 2009 were resolved by the Coppermine-Tivy Valley-Reedley 70 kV maintenance project. This project was completed on September 30, 2008. The ISO had not modeled the Coppermine-Tivy Valley-Reedley 70 kV maintenance project in its analysis for the final 2009 transmission plan because the base cases for the 2009 analysis were developed in April 2008, *i.e.*, before the maintenance project was completed. Thus, although the Tivy Valley-Reedley maintenance project was listed in the Final 2008 ISO Transmission Plan as part of the study assumptions list, the ISO failed to

model it in the base cases used in the 2009 Transmission Plan. However, the maintenance project was modeled in the 2010 planning cycle, and the ISO found that there is no reliability problem in the area. Thus, there is no need for any new transmission project in the area.

15. Ms. Mueller also claims at paragraphs 91-92 of her affidavit that there are no any reliability problems because the base cases show that the breaker on the Coppermine-Tivy Valley line has been opened, and that this results in load shedding in response to Category B events. This is incorrect. I have downloaded the information available to stakeholders for the planning year 2014 (the 2014 base case specifically studied by the ISO in its expansion plan), and the diagram attached to this affidavit shows that the breaker on the Coppermine-Tivy Valley line is not open, contrary to Ms. Mueller's claim. It should be noted that the planning year 2010 base case, which is also posted, does have this breaker as being open, reflecting past operating practices. In any event, the breaker should be closed as reflected in the analysis of 2014 because the Coppermine-Tivy Valley-Reedley maintenance project resolved the past overload concerns; if there is a need to open the breaker in future years it would be for operating conditions beyond planning assumptions. Thus, no load dropping in response to Category B events is planned for this contingency.

D. WGD's Weedpatch 70 kV Energy Storage Project

16. Ms. Mueller notes at paragraph 96 of her affidavit, that WGD proposed the Weedpatch Storage project to address a single contingency (Category B)

thermal overload identified by the ISO in the September 15, 2009 Reliability Assessment results for the 2010 Transmission Plan, namely that the loss of the Wheeler-Weedpatch 70 kV line while Kern Canyon generation is offline will cause an emergency overload of the line between San Bernard and Stalin Jct. 70 kV (see WGD's Weedpatch request window submission form attached to the ISO's answer).

17. As the ISO noted in the 2010 Transmission Plan (pages 188-89), there is an existing operating procedure to open the Weedpatch CB 42 breaker during the summer months to prevent any emergency overloads on the line. Ms. Mueller suggests that opening the breaker during the summer months essentially de-loops an otherwise interconnected transmission system and places the substations on less reliable radial configuration. Mueller Affidavit at P 97. As indicated in the 2010 planning process, that procedure was most recently used during the summer of 2009 and there were no reliability problems. The ISO's initial technical studies were based on a closed breaker. When the ISO conducted a study with the breaker open, there was no overload. Opening the breaker shifts the load to a radial line during the summer months.The ISO's final study results for the Kern local area, with the breaker open. are reflected at pages 181-189 of the final 2010 Transmission Plan, and they do not identify any overload on this line as the result of the Category B event identified by WGD and Ms. Mueller.

18. In Paragraph 100 of Ms. Mueller's affidavit, she states that load dropping in response to a Category B event is an acceptable alternative in lieu of building transmission under the CAISO planning standards, but the ISO must first obtain Board approval to implement a load shedding scheme in lieu of building a project to address the identified Category B event and provide a notification period to stakeholders with an opportunity to respond. In its written comments sent to ISO Management on March 2, 2010 regarding the ISO's proposed recommendations and treatment of the WGD projects, WGD never raised this argument. I would point out that the draft 2010 transmission plan (page 190) – on which stakeholders had an opportunity to submit comments – and the final 2010 transmission plan (page 188-89) identified the procedure to open the Weedpatch CB42 breaker to prevent overloads on the line and indicated that the ISO was rejecting WGD's proposed storage project that was intended to address the same reliability performance problem that opening the breaker resolves. The transmission plan was provided to the Board and discussed in a presentation at the Board meeting.

19. As WGD stated in its request window submittal form, San Bernard to Stalin Jct shows a 100% loading in 2014. That was with the beaker closed. The study with the breaker closed showed a 1% overload in 2019. This area has a very small and rather insignificant load growth between years. The ISO will continue to monitor the situation and in future planning cycles will communicate to stakeholders if existing operating

procedure should be continued, new transmission expansion plans are more suitable solution or no action is needed (load may be trending downward in future load forecast).

E. WGD's Potrero 115 kV Energy Storage Project

20. At paragraph 102 of her affidavit, Ms. Mueller states that WGD proposed the Potrero Energy Storage Project to address the ISO's 2010 Local Capacity Technical Analysis Final Report and Study results which indicated that after the Trans Bay Cable and Martin-Bayshore-Potrero #1 and #2 re-cable are operational, the local capacity requirement would be 25 MW in 2010, 15 MW by 2011, and 10 MW in 2013. She argues that the ISO found that there was no need for the Potrero storage project because the ISO relied on a significant reduction in load forecast and updated line ratings for the Martin-Bayshore-Potrero cables as the result of a PG&E re-cabling project. Mueller Affidavit at P 103. She contends that the ISO arbitrarily changed the planning assumptions in order to prevent independent transmission from being built. Mueller Affidavit at 106.

21. As an initial matter, I note that WGD relied on the ISO's local capacity technical study ("LCR technical study") as the basis for the submission of its reliability project. The ISO conducts the LCR technical study to comply with resource adequacy requirements as set forth in Section 40.3.1 of the ISO Tariff. As indicated in the 2010 Transmission Plan (pages 7-8), the LCR study serves three basic purposes: (1) it identifies the minimum

quantity of local resource that must be procured in order to comply with Section 40.3 of the ISO tariff applicable to Resource Adequacy requirements, titled *Local Capacity Area Resource Requirements Applicable to Scheduling Coordinators for All Load Serving Entities*; (2) it provides a basis for allocating to load serving entities their next year's local capacity requirements; and (3) it establishes the basis for potential local capacity procurement by the ISO under the terms of the Interim Capacity Procurement Program should LSE procurement of generation capacity be deemed insufficient. The local capacity technical study is not a reliability study and is not used for the purpose of identifying thermal overloads and voltage problems in order to comply with NERC planning criteria. The ISO achieves that through its Reliability Assessment study, and stakeholders are supposed to propose reliability projects in response to the needs identified in that study.

22. Ms. Mueller provides no support for her claim that the ISO allowed PG&E to arbitrarily change line ratings to avoid the need only for independent transmission projects. The base cases build for the 2011 and 2013 Long-term LCR studies were developed around September of 2008 and the base cases for the 2010 LCR study were developed around January 2009. At that time PG&E supplied ISO with their best estimate of ratings for the re-cabling projects in San Francisco (to be in service in mid-to-end-of 2010). In August 2009, PG&E provided updated ratings which were approximately 30% higher than what was estimated earlier. These rating

results are determined through extremely complex analysis considering environmental, soil, and installation characteristics as well as equipment characteristics and are not arbitrary changes. The ISO reviewed those updated ratings and found them to be reasonable. I note that the final ratings for the lines that have been inserted into the ISO register are consistent with the updated line ratings that PG&E provided to the ISO in August of 2009. The draft 2010 Transmission Plan used those updated ratings and the ISO found there were no overloaded facilities that required additional generation in San Francisco. In its February 16, 2010 presentation to stakeholders on San Francisco results, the ISO staff listed this conclusion as a bullet in the Key Findings section. The 2010 Transmission Plan and final study results at http://www.caiso.com/2771/2771e57239960.pdf clearly find at pages 153-54 and page 276-79 that as a result of the re-cabling of the Martin-Bayshore-Potrero lines, which significantly increased the ratings of these lines, there are no identified overloads in the area, and that Potrero 3, 4, 5 and 6 can be released from their RMR designation as a result of the Trans Bay DC cable and these San Francisco re-cabling projects. I note that A-H-W #2 (Martin-Bayshore-Potrero#2) became operational on May 24, 2010, A-H-W#1 (Martin-Bayshore-Potrero#1) became operational on December 5, 2010, and Trans Bay DC Cable became operational November 23, 2010. There have not been any reliability problems or other problems resulting from the updated line ratings that the ISO used in connection with the final 2010 study results and 2010 transmission plan.

23. Ms. Mueller also alleges that the ISO arbitrarily changed its load forecast assumptions for the purposes of rejecting WGD's project. The updated line ratings were more than sufficient by themselves to address any overload concerns regardless of load forecast used (2009 or 2010 version); the ISO did not rely on a reduced load forecast for the area as the basis for rejecting the Potrero storage project. That is why the final 2010 Transmission Plan (page 153-54) indicated that the re-cabling addressed all reliability needs and there was no need for an additional transmission project in the area.

24. Finally, Ms. Mueller alleges that the ISO did not provide a stakeholder notification period or receive Board approval for a system configuration that would drop load in lieu of building transmission. Mueller Affidavit at P 107. Ms. Mueller provides no support for her claim. There never was any single contingency load shedding or loss of load in this area since about 362 MW of existing resources were available to meet the small LCR need presented in the old LCR studies. Furthermore, as a result of the updated line ratings, there are no longer any potential Category B overloads that require the building of additional transmission projects or the retention of any existing resources to meet LCR needs in the area. This is borne out

in the final study results for the San Francisco Bay Area reflected in the final 2010 Transmission Plan. 2010 Transmission Plan at 279-84.

25. I note that both the new DC Trans Bay cable and PG&E's San Francisco re-cabling projects (with the final – higher ratings) are in service. Therefore, there is no local capacity requirement for San Francisco area. The ISO has already sent a letter to Mirant in order to release all Potrero units from their RMR status as of January 1, 2011. These units will be shut down and retired.

26. At this time the ISO considers the Potrero reliability issues resolved and no further action is needed in order to meet reliability standards.

F. WGD's Madison 115 kV Energy Storage Project

27. Ms. Mueller states that WGD submitted the Madison Energy Storage project to address normal (category A) thermal overloads in the Madison Area, as outlined in the ISO's Reliability Assessment study results. Mueller Affidavit at P 108. At paragraph 109 of her affidavit, she notes that the ISO found that the there was no need for WGD's storage project or any other transmission upgrade because the Vaca-Madison 115 kV line could be re-rated at minimal cost, thereby eliminating any overloads and deferring the need for new transmission for approximately 12-15 years. In paragraph 112, Ms. Mueller alleges that the ISO allowed its unified planning assumptions to be arbitrarily updated by incorporating updated line ratings, in order to eliminate the need for WGD's project.

28. Transmission line re-rates can be a low cost alternative that should always be an alternative for relatively small overload (less than 12-15%). The ISO is routinely considering the potential for line re-rates in its planning assessments taking advantage of implementation of better technology and better access to accurate environmental data. This enables more precise rating assumptions compared to the old and generally conservative assumptions traditionally employed by transmission owners in the past. For example, all old PG&E equipment is rated based on assumptions of 2 feet/second wind speed. However, based on actual wind speed data collected in the area at peak periods, a re-rate can most likely be considered based on 4 feet/second for most counties in the PG&E service territory and on 3 feet/second on a few select counties. The re-rate can only be considered on a line-by-line basis since each line also needs to be patrolled to check that its clearances are sufficient to manage the extra sagging that may result from higher current flowing through the line. The ISO has a reference document that enables it to estimate for all conductor sizes and voltage levels whether a successful re-rate will mitigate the expected small overload. The reference document shows that the re-rated levels proposed for the Vaca-Madison line were consistent with the guidelines in the reference document.

29. Based on my experience, the cost of a re-rate is often minimal, usually less than $100,000 for a facility like this one. On the other hand, WGD's estimated the initial capital cost of their proposed battery was $4.5 million

for a 3 MW battery, and additional capital costs would be incurred as additional battery capacity is added in increments of 3 MW, 4 MW, or 5 MW for the next 30 years. The ISO expected on average the re-rating to increase the rating of the line by approximately 12-15%. Because the Vaca-Madison 115 kV line loading is increasing at a rate of about 1% per year (see page 88, Table 3-3.4.6 line 2 (CVLY-T-041) in the 2010 ISO expansion plan at: http://www.caiso.com/2771/2771e57239960.pdf where the 105% loading in 2019 minus 100% loading in 2014 divided by 5 year results in 1% per year), the ISO believed that a successful re-rate would mitigate the reliability need for approximately 12-15 years, thereby moving the need for a transmission project to 2027-2030 timeframe. Re-rating the line from a 2 feet/second wind speed to 4 feet/second wind speed, where possible, is technically feasible and has been implemented successfully at numerous locations across the ISO's footprint. Once the line was successfully re-rated to a higher value, there is no thermal overload or any other reliability problem. Ms. Mueller does not raise any objections regarding the line's updated rating or offer any support for her claim that the updated line rating is incorrect or unjustified from an engineering basis.

30. WGD's claims that the ISO allowed its planning assumptions to be updated in order to eliminate the need for WGD's project and that the ISO should not allow PG&E to arbitrarily change its line ratings in order to avoid independent transmission is misplaced. The re-rating of the

Madison-Vaca line was documented in the draft Transmission Plan, the ISO's presentation at the February 16, 2010 stakeholder meeting, the final 2010 Transmission Plan which contains the final study results, and in the ISO's May 5, 2010 letter to WGD. WGD never objected to the revised line ratings during the stakeholder process, and, in its complaint, WGD does not contend or offer any evidence that the use of updated line ratings was unjustified and unsupportable from an engineering standpoint.

31. Mr. Alaywan appears to compare in his economic analysis WGD's Madison 115 kV Energy Storage project with PG&E's Vaca Dixon-Davis 115 kV conversion (see for reference: Madison Vaca Site Cost Comparison based on WGD Madison Project Page 24 of 33, Attachment A, Alaywan Affidavit, compared to PG&E Vaca Dixon-Davis Voltage Conversion Page 27 of 33, Attachment A, Alaywan Affidavit). This project is also known as the Woodland-Davis-West Sacramento Long-Term project. I must note these two projects address totally different reliability needs (as reflected by the tables on pages 88-110 of the 2010 Transmission Plan),and the WGD Madison 115 kV Energy Storage Project is not an alternative to the PG&E Vaca Dixon-Davis 115 kV conversion.

G. WGD's Guernsey 70 kV Energy Storage Project

32. WGD submitted the Guernsey 70 kV Energy Storage Project to address a normal (Category A) thermal overload on the Corcoran 70 kV transformer bank. In the 2010 Transmission Plan (pages 173-174) the ISO rejected the project because, among other things, it was not the most cost-effective

solution for meeting the identified reliability need. The ISO noted that if it approved a battery storage project, additional costs would still have to be incurred to replace the existing transformer which was extremely old and slated for replacement in the next couple of years. The ISO found that the transformer replacement would not only resolve the identified reliability need, it would replace the transformer that was already going to be replaced anyway in a few years. Thus, the project approved by the ISO essentially "killed two birds with one stone." Based on its review of WGD's request window submission, the ISO also concluded that approval of a battery storage device would require two new special protection schemes and associated operating procedures.

33. In her affidavit at paragraph 123, Ms. Mueller further clarifies WGD's proposal and the configuration they envisioned in their request window submission. The ISO may have misunderstood the exact configuration required for WGD's Guernsey storage project; however, WGD's request window submission does not provide a clear description of the system under normal conditions and all plots provided are under emergency conditions only. Although the description in the request window submission indicates that if installed at Guernsey this substation needs to be normally served from Corcoran, it does not indicate that the existing main feed from Henrietta would need to be opened and left normally open.

If Guernsey is only served from Corcoran in a radial configuration, then I would agree that the two additional SPSs would not be needed.

34. However, eliminating the need for the two additional SPSs would not change ISO preferred alternative which is to replace the existing transformer at Corcoran with a new standard transformer. This is the most cost effective solution for ratepayers. This bank is 79 years old and if not changed now through the replacement project it will need to be changed out in 2013 at the same cost (or potentially higher cost) to ratepayers. Because the transformer would need to be replaced even if the ISO approved a battery storage project and merely replacing the transformer will resolve the reliability problem, it is clearly the most cost effective solution to resolving the identified reliability problem. This area has no interim reliability concerns since distribution load is moved to other surrounding substations not served from Corcoran until the old transformer is replaced.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Catalin Micsa

DECLARATION OF

PAUL DIDSAYABUTRA

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Technology Solutions, LLC and Western Grid Development, LLC, Complainants,	)	
v.	)	**Docket No. EL11-8-000**
California Independent System Operator Corporation, Respondent.	)	

DECLARATION OF PONPRANOD DIDSAYABUTRA

I, Ponpranod Didsayabutra, declare as follows:

I. QUALIFICATIONS AND PURPOSE

1. My name is Ponpranod Didsayabutra. I am employed by California Independent System Operator Corporation, Inc (ISO) as a senior regional transmission engineer.
2. I received Bachelor, Master, and Ph.D degrees from Chulalongkorn University, Thailand. All in electrical engineering. During the course of my Ph.D program, I was a research scholar at the University of Texas at Arlington while conducting my Ph.D dissertation. I also received a certificate in Business Administration from the University of California at Berkeley Extension.
3. I have been employed at the ISO for over 8 years. I am responsible, among other things, for conducting reliability assessment studies and other technical

studies to ensure the ISO grid is planned according to the reliability standards.

4. I participated in the evaluation of the reliability-driven transmission proposals submitted by Transmission Technology Solutions, LLC ("TTS") and Western Grid Development, LLC (WGD) into the ISO's 2009 and 2010 transmission planning cycles. I drafted portions of each version of the 2009 and 2010 Transmission Plans, including the amendment to the 2009 final Transmission Plan.
5. The purpose of my affidavit is to respond to claims set forth in the affidavits of Jenny Mueller and Ziad Alaywan that the ISO erred in rejecting certain reliability-driven transmission solutions submitted by TTS and WGD in the 2009 and 2010 Transmission Plans. I also provide some factual information about the ISO's transmission planning process during the 2009 and 2010 planning cycles.

II. THE TTS PROJECTS

A. Background Information

6. The ISO implemented its revised Order 890 transmission planning process in 2008 for the 2009 planning cycle that ended with the amended transmission plan on June 8, 2009. Because the ISO submitted changes to the process on October 31, 2008 (in compliance with the FERC's June 19, 2008 order), the ISO extended the request window until December 15, 2008.
7. TTS submitted its proposals on the last day of the request window, December 15, 2008. This timing gave the ISO a compressed period of time to study the

TTS proposals as alternatives to the permanent mitigation solutions proposed by the participating TOs making it unlikely that the analysis could be completed by the time the draft 2009 Transmission Plan was posted on February 13, 2009.

8. The ISO staff based its evaluations of the TTS projects on the information and studies submitted with the request window packages. In contrast to the economic analysis described in Mr. Alawayan's affidavit with respect to the TTS proposals, TTS did not provide any direction in the request window packages about how the ISO staff should compare the costs of the TTS leasing arrangements with the capital costs of the long-term capital equipment mitigation solutions proposed by the participating TOs submitted through the request window. The ISO also used the information provided by the participating TOs regarding the permanent reliability projects. In coming to the conclusions in the plan amendment, the ISO did not rely on other information submitted outside the transmission planning process to evaluate the TTS proposals and the reliability projects submitted by the participating TOs.

9. The amendment to the 2009 final Transmission Plan, at pages 294-299 describes each TTS interim solution and the reliability "gap" between the in-service date for the TTS proposals and the in-service date of the participating TO's long term solution. For the Watsonville, West Fresno, Garberville and Maple Creek TTS proposals, the reliability "gap" described in the narrative discussions at pages 297-298 was inadvertently calculated and used the date

of the reliability concern rather than the proposed in-service date provided by TTS.

10. At paragraph 25 of her affidavit, Ms. Mueller states that the ISO deviated from the planning assumptions used in developing the ISO staff's preliminary study results and that stakeholders were not made aware of these "deviations." From other sections of her affidavit, I understand what Ms. Mueller means by "deviations" from the preliminary study assumptions are the PG&E operating solutions that address identified reliability concerns on a short-term basis until the permanent mitigation solution is in-service. These short term operating solutions are not deviations from the planning assumptions and are not required to be submitted through the transmission planning request window. Changes in operating procedures or facility re-rates may occur frequently any time of year because these procedures are related to real-time operations and, typically, do not require new construction of new transmission facility that require TAC recovery. Ms. Mueller is incorrect in her conclusion that the ISO did not follow the tariff or BPM in considering operating procedures as viable and cost-effective interim solutions during the gap period before the permanent project is in service.

B. Individual TTS Projects

1. Maple Creek Interim Solution

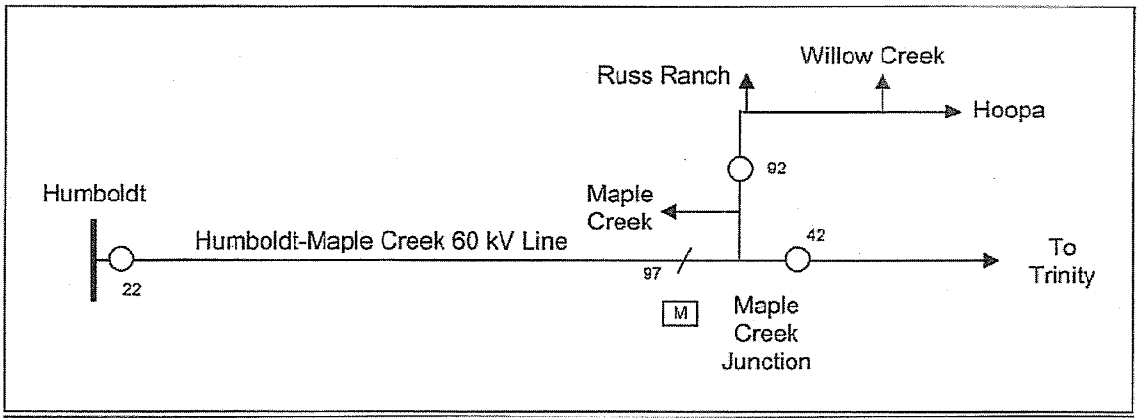
11. Ms. Mueller's statement at paragraph 38 of her affidavit that "the ISO plan to drop load in lieu of building transmission" at this location is incorrect and misleading. As clearly indicated on page 58 of the 2009 ISO Transmission

Plan, the ISO proposed solution for low voltages at Maple Creek and vicinity substations is to add reactive support in this area. Consistent with the ISO's findings, PG&E proposed a capital project to install a reactive support device to mitigate low voltage problems. The PG&E "plan" to address low voltage conditions in the Maple Creek area was to install reactive support, not to drop load. I also would point out that the mitigation solution identified by ISO staff and adopted by PG&E is to install 10 MVAR of reactive support at the Maple Creek substation. The TTS proposal is to install 50 MVAR, which is too large for the identified issues.

12. The short-term solution developed by PG&E is the least cost solution in the interim period until the long-term project is completed. To the best of my knowledge, the cost to implement the operating procedure is very small or negligible compared to the capital project.

13. The short-term plan adopted by PG&E and described in the letter to FERC enforcement staff is to temporarily disable automatic switching that would otherwise try to recover load that has already been dropped as part of the contingency. As shown in figure 1, loss of Humboldt – Maple Creek 60 kV line will result in loss of loads at Maple Creek, Russ Ranch, Willow Creek, and Hoopa. The automatic switching scheme simply tries to restore these loads with Trinity substation. However, the study results show that under certain conditions this action may result in low voltage concerns under certain conditions. Consequently, a long-term transmission plan should be placed in-service to mitigate the low voltage concerns. As an interim period, the

automatic switching should be disabled under such conditions e.g. high peak demand periods. The study results also show that the implementation of this mitigation plan will not impact the overall reliability of the interconnected transmission systems.

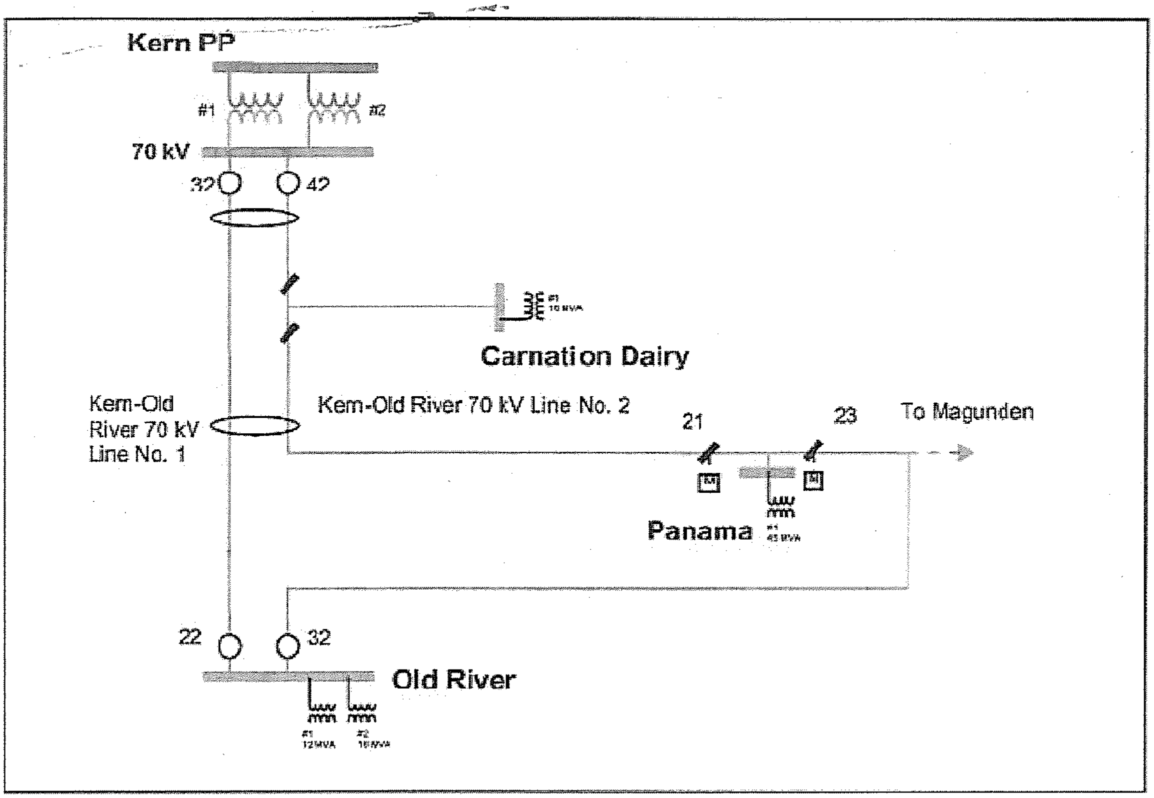


2. Old River Interim Solution

14. The ISO approved the PG&E's Kern-Old River Nos. 1 and 2 70 kV lines reconductoring as a cost-effective permanent solution to address both overload and undervoltage conditions. This project is the "plan" to address the reliability concerns and it does not involve load dropping. ISO staff determined that the TTS proposal could improve voltage in the area from dropping below 0.95 PU but could not mitigate the potential thermal overload conditions identified in 2010. Since the in-service date of the TTS proposal was October, 2010, it would be in service after another mitigation solution would have to be implemented to address the thermal overload conditions in the area that could occur in 2010.

15. The PG&E interim solution is similar to the procedure put in place for the Maple Creek area. As shown in the diagram below, when a sustained fault

occurs on Kern-Old River 70 kV line no. 2, circuits breakers no 42 and 32 (on the Old River side) would open and isolate the fault. PG&E has installed two motor operated switches (Nos. 21 and 23) at the junction point where Panama substation connects to Kern – Old River 70 kV No. 2 lines. These switches enable PG&E to restore electric service to Panama substation. For example, once the fault occurs between Kern Power Plant and Panama, the Kern Power Plant Circuit Breaker No. 42 and the Panama Switch No. 21 would remain open. Service will be restored to load served from the Panama bus by closing the switch number 23 (shown above box M in the diagram) and circuit breaker number 32. The restoration switching sequence would take about 30-60 seconds. In response to potential concerns prior to the completion of the reconductoring project, during summer months, PG&E will disable the automatic restore feature on Panama switch no. 23.



3. Watsonville Interim Solution

16. In the Watsonville area, the goals of the ISO were to mitigate the possibility of load dropping and address potential overload by approving the long-term transmission project proposed by PG&E. This approved project, which converts the Watsonville 60 kV system to 115 kV, can eliminate the reliance on an undervoltage load shedding scheme (UVLS) for the Category B conditions developed by PG&E in 2001and implemented in 2002 as a safety net. The permanent capital project is much broader in scope and has the additional benefit of mitigating not only the thermal and voltage concerns in the area under Category B contingency but also the potential risk of Category C loss of customers.

17. The TTS proposed "remedy" described in Attachment 1 to Ms. Mueller's affidavit, as well as the economic analysis proposed by Mr. Alawyan, proposes the deferral of PG&E's Watsonville Voltage Conversion Project. Similar to the Old River situation, this reveals a flaw in TTS study because it focuses narrowly on low voltage in a small area without considering negative impacts from deferring the long-term project by PG&E. Basically, as part of its scope, the conversion project was designed to address thermal overloads,low voltages and potential loss of customers. According to the PG&E 2008 Electric Transmission Reliability Assessment Study for the Central Coast and Los Padres area, unless the Watsonville Voltage Conversion Project is in-service, a double circuit tower line outage of the Moss Landing – Green Valley lines could result in over 60,000 customers in Santa Cruz County being without power until one line can be restored. In addition, the Moss Landing – Green Valley 115 kV Line can be overloaded following the outage of Moss Landing – Green Valley No.1 115 kV Line and the CIC Cogen unit.

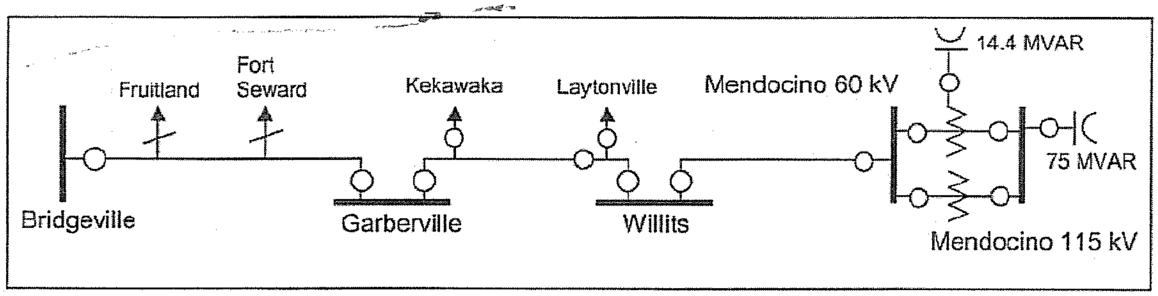
18. The Watsonville Voltage Conversion Project will create a stronger 115 kV connection to Green Valley 115 kV and Crazy Horse 115 kV buses with Watsonville. As a result, in addition to improving voltage profile in Watsonville area, it also alleviates power flow on the Moss Landing – Green Valley 115 kV Lines that results in lower loading on these lines under both normal and emergency conditions. The voltage conversion project also reduces the risk of customers being without power due to the double circuit tower line outage (Category C conditions). Consequently, with the

Watsonville Voltage Conversion Project, potential overloads on Moss Landing – Green Valley 115 kV lines that were identified can be averted. Consequently, TTS proposal to defer this project would results in lower reliability of the system.

4. Garberville Interim Solution

19. Like the Maple Creek area, the ISO identified a need for reactive support at the Garberville substation and PG&E proposed a permanent solution to install 20 MVAR of reactive support. Once again, the TTS proposal to install 50 MVAR in this location would be excessive to address the identified need.

20. For the interim period until the PG&E project is in service, PG&E will use an operating procedure that calls for changing the regulator setting on the Mendocino 115/60 kV transformers. This particular operating procedure has been in effect in PG&E's Fulton control center since 2009. The regulator adjustment would be made in the event that low voltage conditions at Bridgeville, Fruitland, and Fort Stewart substations are projected. As shown on the figure below, in this scenario, PG&E would increase regulator settings on the Mendocino 115/60 kV Transformer Nos. 1 and 3 to raise voltages in the area in response to low voltage situations. However, the Mendocino transformer is approximately 70 miles away from the Garberville bus and therefore the regulator adjustment solution is only a temporary solution until the permanent solution- the Garberville reactive support solution- can be put in place.

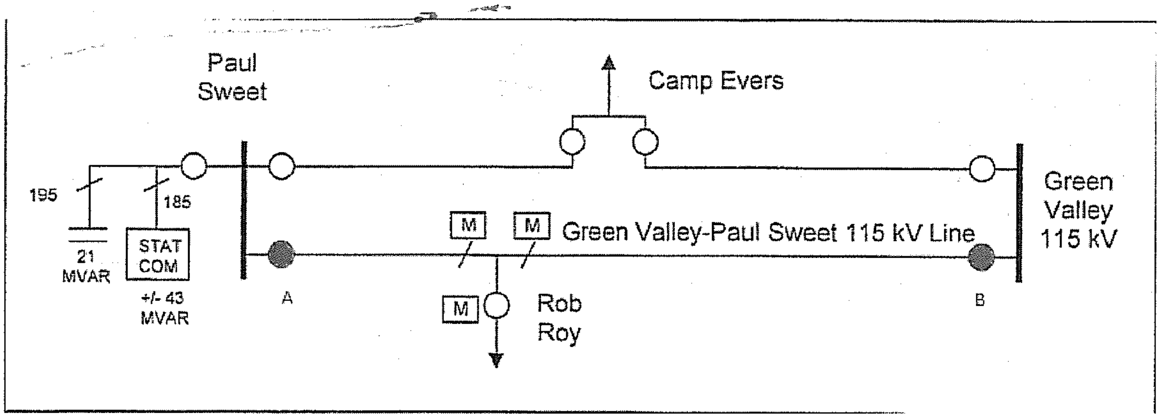


21. Ms. Mueller's suggestion, at paragraph 53 of her affidavit, that this interim solution be made into a permanent solution which would eliminate the PG&E project, is not consistent with good utility practice and should not be adopted. It also contradicts TTS's position in this case with respect to system reliability. By recommending that a change in regulator settings be adopted as a permanent solution, TTS appears to suggest a lower reliability option rather than a capital project. On the contrary, as a general practice, the ISO would approve long-term transmission projects that minimize the need to rely on short-term solutions such as operating procedures.

5. Camp Evers Interim Solution

22. The ISO approved the PG&E long-term permanent solution for the Santa Cruz area, the Santa Cruz 115 kV reinforcement project. This is the "planned" solution for low voltages at Rob Roy in the Camp Evers area and it does not involve load shedding.

23. During the short term reliability gap, PG&E has in place an operating procedure that is a cost effective mitigation solution. The PG&E interim solution was implemented in 2005 when PG&E installed two motor operated switches at the junction point where the Rob Roy substation connects to the Green Valley- Paul Sweet 115 kV line as shown in the line diagram below.



24. A sustained fault on the Green Valley – Paul Sweet 115 kV line would open circuit breakers A, B, disconnecting load at Rob Roy. These new switches enabled PG&E to restore electric service to Rob Roy by isolating sustained fault on the Green Valley – Paul Sweet 115 kV Line and reclosing the un-faulted segment to restore the load.

25. A sustained fault on the Green Valley-Paul Sweet 115 kV line together with the Paul Sweet STATCOM out of service would disconnect Rob Roy Substation from the grid. However, depending on system conditions and the availability of the Paul Sweet station capacitors, PG&E may be unable to restore electric service at Rob Roy substation due to voltage concerns. Consequently, for the short period of time before the permanent solution is implemented, PG&E has implemented an interim solution to mitigate these issues. If and when the Paul Sweet STATCOM is out of service during winter months, PG&E would manually switch in the 21 MVAR station capacitors at Paul Sweet as needed, to raise voltage level. If these capacitors are not available, or if PG&E or ISO operators still have concerns about low voltage, PG&E would manually disable the automatic reclose on the Paul Sweet circuit breaker No 162. Reliance on this interim solution is

very short since the expected in-service date of the Santa Cruz 115 kV Reinforcement project is December 2011.

6. Cal Cement Interim Solution

26. Ms. Mueller inaccurately assumes, at paragraph 60 of her affidavit, that with respect to potential undervoltage situations in the Antelope-Bailey area, SCE would either violate reliability standards or interrupt load until such time as the permanent mitigation solution is in service. Ms. Mueller's assumption is incorrect.

27. SCE implemented an operating procedure to address the interim gap, and it does not involve load dropping. This operating procedure, OP 068, would curtail output resources in the area to mitigate potential overloads and voltage concerns that were identified without dropping the load. Furthermore, a long term solution for the under-voltage concerns in the area was approved in the 2010 cycle as part of the East Kern Wind Resource Area (EKWRA) 66 kV reconfiguration.

III. WGD'S TULUCAY 60 KV ENERGY STORAGE PROJECT

28. Ms. Mueller states at paragraph 113 of her affidavit that WGD proposed the Tulucay Storage project to address the 2010 CAISO Local Capacity Technical Analysis which indicated that the Vaca-Dixon-Tulucay 230 kV line will reach 100% of its emergency rating for loss of the Vaca Dixon-Lakeville 230 kV line with the Delta Energy Center (DEC power plant) offline, and that this overload results in a local capacity requirement of 787 MW (Page 3 of the final 2010 LCR report http://www.caiso.com/2495/2495c69b28da0.pdf) in the

North Coat/North Bay Sub-Area. In its request window submission, WGD proposed to install a storage battery at the Tulucay bus to address LCR need. Ms. Mueller states that WGD was not aware that there was also an the overload on the Vaca-Dixon-Lakeville line at the time it submitted its project in the request window, and that a simple solution to the second overload on the Vaca Dixon-Lakeville Line would be to change the point of the interconnection of the WGD storage project from Tulucay to Lakeville so that the battery can resolve both constraints. Mueller Affidavit at P 118. 29.According to WGD, the Tulucay Energy Storage "will reduce overall Local Capacity Requirement (LCR) for the North Coast/North Bay area by 42 MW". The ISO evaluated this proposal under the guise of the LCR as the WGD proposed and provided its finding in both the 2010 ISO Transmission Plan and the letter that was sent to WGD on May 5, 2010. Based on an analysis from an LCR perspective, the ISO found that the 25 MW real power output from Tulucay Energy Storage can relieve power flow on the Vaca Dixon – Tulucay 230 kV line triggered by the outage of Delta Energy Center and Vaca Dixon – Lakeville 230 kV Line (the limiting facility and the most critical contingency for LCR in North Coast/North Bay area that was identified in the 2010 LCR study report). However, the battery storage unit exacerbated loading on the parallel 230 kV line (Vaca Dixon – Lakeville 230 kV) with the outages of Delta Energy Center, combining with the Lakeville – Tulucay 230 kV line. Accordingly, although the ISO found that from an LCR perspective the Tulucay Energy Storage might reduce LCR requirements in the North Coast/North Bay area driven by the most critical contingency identified by the 2010 ISO LCR study, it would increase LCR requirement driven by the underlying contingencies. Consequently, the Tulucay Energy Storage would not provide the level of benefits claimed by WGD. Consequently, from the LCR perspective, the proposal addressed only one of the two potential overloads related to LCR in the area.

29. Also, in order to address the ISO's LCR resource needs, the battery storage unit would need to function as a generator, not as a transmission element, because it would need to generate real power to the grid to provide LCR reduction and reduce load on the limiting facilities. As confirmed by the Request Window submission by WGD, figure 2 in the WGD application form shows this project generates only 25 MW of real power. No reactive power is generated from the proposal. However, it is my understanding that WGD proposed, and was required by FERC, to utilize the battery storage element as a transmission element to resolve reliability problems and not as a generator.

30. With respect to an assessment of the ESD from the perspective of the ISO's Reliability Assessment study results, I note that ISO's Reliability Assessment that was conducted in mid 2009, as part of the 2010 Transmission Plan also identified potential overloads on the Vaca Dixon – Lakeville and Tulucay - Vaca Dixon 230 kV lines. On page 8 of the ISO reliability assessment results that was posted on September 17, 2009, items NCNB-S-T-003 and NCNB-S-

T-004 [http://www.caiso.com/242a/242ae4765f2d0.pdf] showed potential overloads on these two lines in both 2014 and 2019 study scenarios. Following the posting of the study results, the ISO also presented these study results during the October 26, 2009 stakeholder meeting. These two overloads are shown in the diagram on page 10 of the Overview, Bulk, Humboldt, North Coast, and North Bay Reliability Study Results presentation [http://www.caiso.com/244e/244eee2946bb0.pdf]. In addition, these results are reflected in the 2010 ISO Transmission Plan report in two places. First, Page 47 of the 2010 ISO Transmission Plan reiterated the findings on September 17, 2009 by reporting potential overloads on both 2014 and 2019 study scenarios. Second, while discussing potential overloads on the Vaca Dixon – Lakeville and Tulucay – Vaca Dixon 230 kV Lines in more details, page 65 of the final 2010 Transmission Plan indicated "*The ISO reliability study results showed that mitigation plans are needed for potential overloads on 1) Vaca Dixon – Lakeville and 2) Vaca Dixon - Tulucay 230 kV Lines. In addition, the ISO LCR study results also show that the Vaca Dixon - Tulucay 230 kV line is the limiting facility that drives LCR requirements in the North Coast/North Bay area*" to explain two technical studies that identified overloads on transmission lines in this area.

31. From the reliability assessment perspective, the ISO found that 25 MW real power output from the Tulucay Energy Storage may reduce power low on both lines under the worst contingencies. However, since the proposal reduces less than 3% of loading on the limiting facilities, the identified

overloads still exist. The reliability assessment showed potential 109.9% loading on Vaca Dixon – Tulucay 230 kV line with the outages of Vaca Dixon – Lakeville and Geysers 9-Lakeville 230 kV lines. If a battery is supplying 25 MW at Tulucay, loading on the Vaca Dixon – Tulucay 230 kV line under this contingency could reduce to 106.8%. Since WGD did not provide the model of its new proposal to move the battery to Lakeville even though now argues that it can move to a new location, loading on the Vaca Dixon – Tulucay under this contingency would be 108.2% assuming the exact model of the battery project is connected at Lakeville 60 kV.

32. Similar findings were found on the Vaca Dixon – Lakeville 230 kV line. The ISO reliability assessment showed potential 111.7% loading on Vaca Dixon – Lakeville 230 kV line with the outages of Vaca Dixon – Tulucay and Geysers 9-Lakeville 230 kV lines. If a battery is supplying 25 MW at Tulucay, loading on the Vaca Dixon – Lakeville 230 kV line under this contingency could reduce to 109.8%. Similar loading of 109.8% was also found assuming the exact model of the battery project is connected at Lakeville 60 kV. Consequently, the storage proposal is not sufficient to relieve the overloads on the Vaca Dixon – Lakeville and Tulucay – Vaca Dixon 230 kV lines that were identified in the reliability assessment.

33. Rather than looking solely at the ISO LCT study results, WGD also should have referred to the ISO's Reliability Assessment results. The ISO uses the Reliability Assessment study to comply with applicable NERC planning standards, identify which facilities do not meet reliability performance requirements during the planning horizon being studied, and to serve as the basis for identifying needed Page 8 of the ISO's 2010 Transmission Plan Reliability Assessment shows that there were two Category C contingencies in the area: an overload on the Vaca Dixon-Tulacay 230 kV Line and an overload on the Vaca-Dixon-Lakeville 230 kV line. Thus, the applicable Reliability Assessment clearly showed that there were overloads on both lines; WGD assumed that there was only an overload on one line because it relied solely on the LCT study which is not a reliability study. Parties are supposed to submit reliability projects in response to the needs identified in the ISO's Reliability Assessment; WGD did not.

34. In terms of resolving the needs identified in the ISO' Reliability Assessment, the proposal is not sufficient to mitigate overloads on both lines triggered by category C contingencies as shown in figures 1-6 below.

35. Ms. Mueller's claim altering the point of interconnection of the WGD Energy Storage Project from Tulucay to Lakeville can resolve both of the identified reliability concerns is incorrect. Regardless of where the battery storage unit is placed, it does not resolve the two overloads identified in the Reliability

Assessment.[1] Thus, even if the ISO were to approve a battery storage project, reconductoring would still need to occur.

36. As shown in figure 1, the 2010 ISO Transmission ISO Transmission Plan report[2] identified the Vaca Dixon – Tulucay 230 kV Line can be overloaded following the outages of Geysers 9 – Lakeville and Lakeville-Vaca Dixon 230 kV Lines. Figures 2 and 3 show that neither the installation of Energy Storage Device at Tulucay (figure 2) nor Lakeville (figure 3) will eliminate this overload. The overload on this line is still exist and the exercise also shows that 1) placement of this Energy Storage at Lakeville reduces only 1.7% power flow on Vaca Dixon – Tulucay 230 kV Line from 109.9% loading to 108.2% 2) placement of this Energy Storage at Tulucay reduces only 3.1% power flow on Vaca Dixon – Tulucay 230 kV Line from 109.9% loading to 106.8%.

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[1] Also, moving the battery from Tulucay to Lakeville would not resolve the additional overload on the Vaca Dixon-Lakeville line. Rather, it reduces power flow on an underlying limitation that can be identified by performing simple power flow studies. As WGD indicated it performed the study to support this project using the 2010 CAISO LCR case, and should be able to easily determine this limitation. Second, WGD did not provide specific location of the new interconnection point that may impact the cost of interconnecting the ESD. However, assuming the Lakeville 60 kV bus is an alternative location, this new location will not yield the same LCR reduction benefit on the most critical contingency as connecting at Tulucay 60 kV. For the most critical contingency, placing an ESD at Lakeville is approximately only 62% as effective as placing ESD at Tulucay in term of reducing power flow from Vaca Dion to Tulucay, Consequently, even though placing an ESD at Lakeville may reduce power flow on Vaca – Tulucay following the most critical conditions and Vaca – Lakeville following underlying contingencies, the benefit from placing ESD at Lakeville is far less than installing at Tulucay.
WGD's analysis also does not acknowledge the fact that any LCR reduction from an Eenrgy Storage device would be very small compared to what a line reconductoring can achieve. While the LCR reduction is relatively small (and even smaller when the unit is moved to Lakeview) a reconductoring of the two line will significantly reduce the LCR requirement, compared to the ESD.

[2] Table 3-3.2.3, page 47 of the 2010 ISO Transmission Plan report (http://www.caiso.com/2771/2771e57239960.pdf)

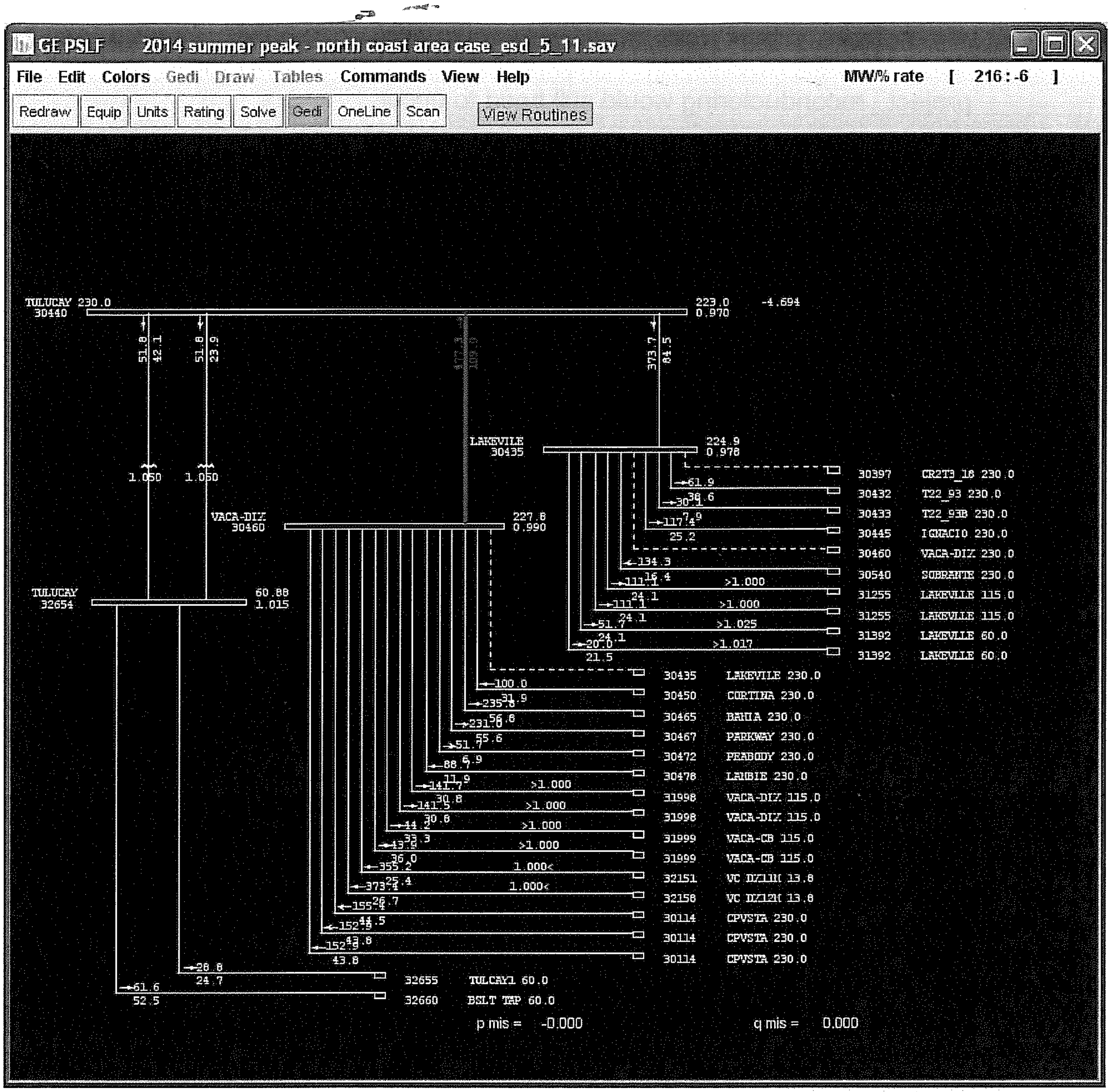


Figure 1 Overload on Vaca Dixon – Tulucay 230 kV line following the outages of Vaca Dixon – Lakeville and Geysers9 – Lakeville 230 kV **lines** as identified in 2010 ISO Transmission Plan

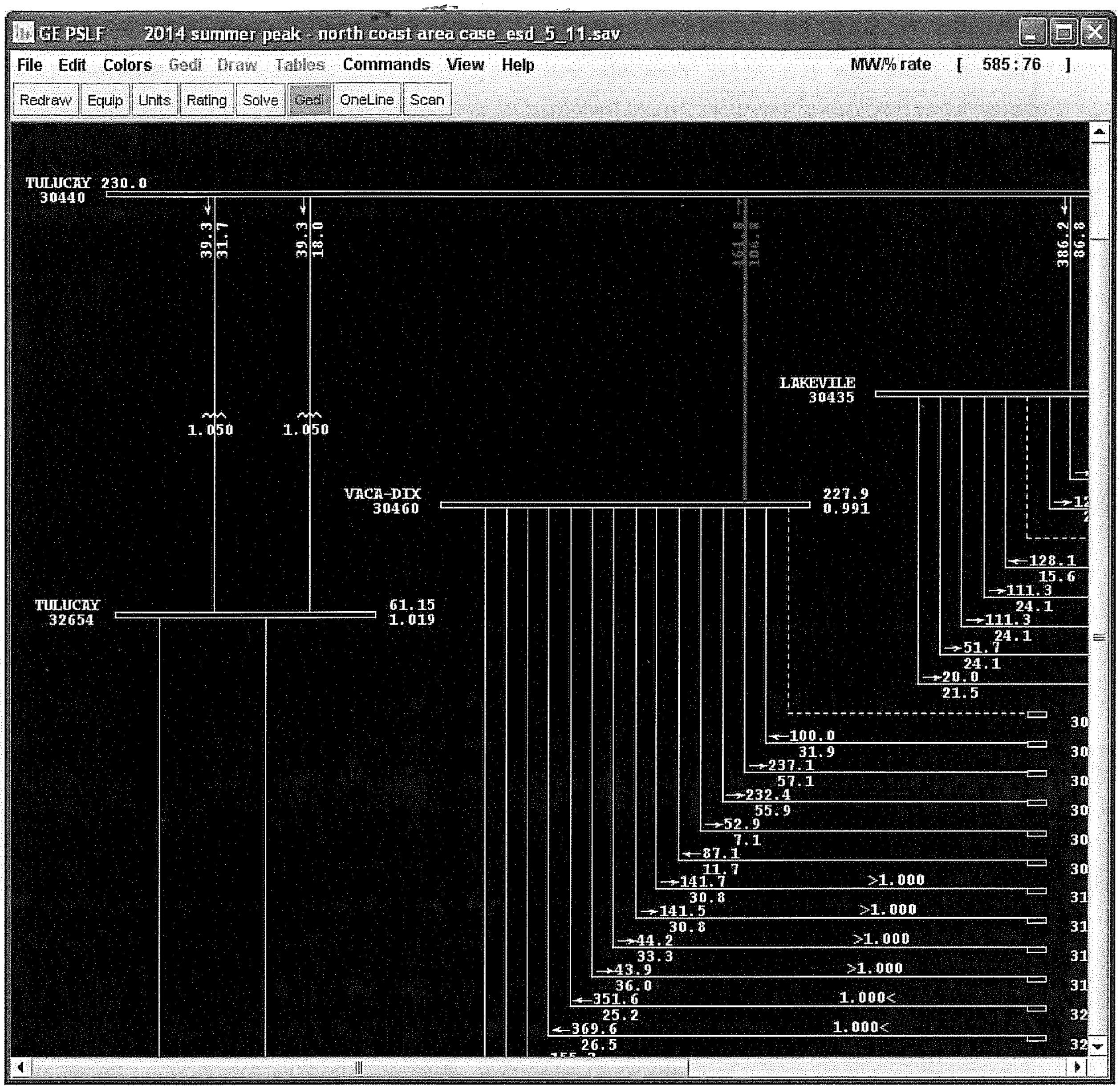


Figure 2 Overload on Vaca Dixon – Tulucay 230 kV line following the outages of Vaca Dixon – Lakeville and Geysers9 – Lakeville 230 kV lines with a 25 MW Energy storage at Tulucay 60 kV Bus

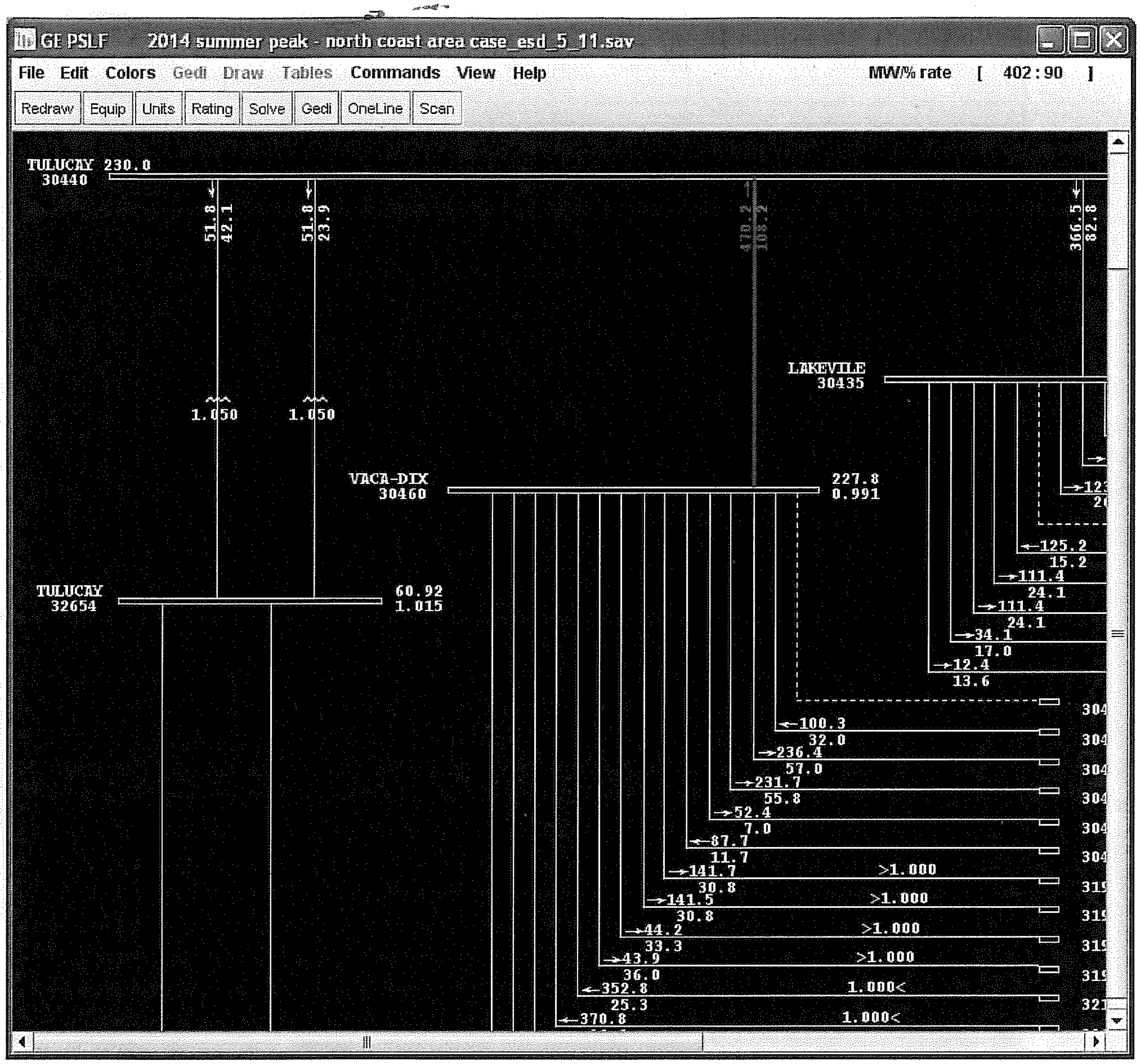


Figure 3 Overload on Vaca Dixon – Tulucay 230 kV line following the outages of Vaca Dixon – Lakeville and Geysers9 – Lakeville 230 kV lines with a 25 MW Energy storage at Lakeville 60 kV Bus

37.Similar results were found on potential overload on Lakeville - Vaca Dixon 230 kV line. As shown in figure 4, the 2010 ISO Transmission ISO Transmission Plan report[3] identified the Lakeville - Vaca Dixon 230 kV Line can be

[3] Table 3-3.2.3, page 47 of the 2010 ISO Transmission Plan report (http://www.caiso.com/2771/2771e57239960.pdf)

overloaded following the outages of Geysers 9 – Lakeville and Tulucay-Vaca Dixon 230 kV Lines. Study results show that neither the installation of Energy Storage Device at Tulucay (figure 5) nor Lakeville (figure 6) will eliminate this overload. The overload on this line is still exist and this exercise also shows that 1) placement of this Energy Storage at Lakeville substation reduces only 1.9% of power flow on Lakeville - Vaca Dixon 230 kV Line from 111.7% loading to 109.8% 2) placement of this Energy Storage at Tulucay substation reduces only 1.9% power flow on Vaca Dixon – Tulucay 230 kV Line from 111.7.9% loading to 109.8%.

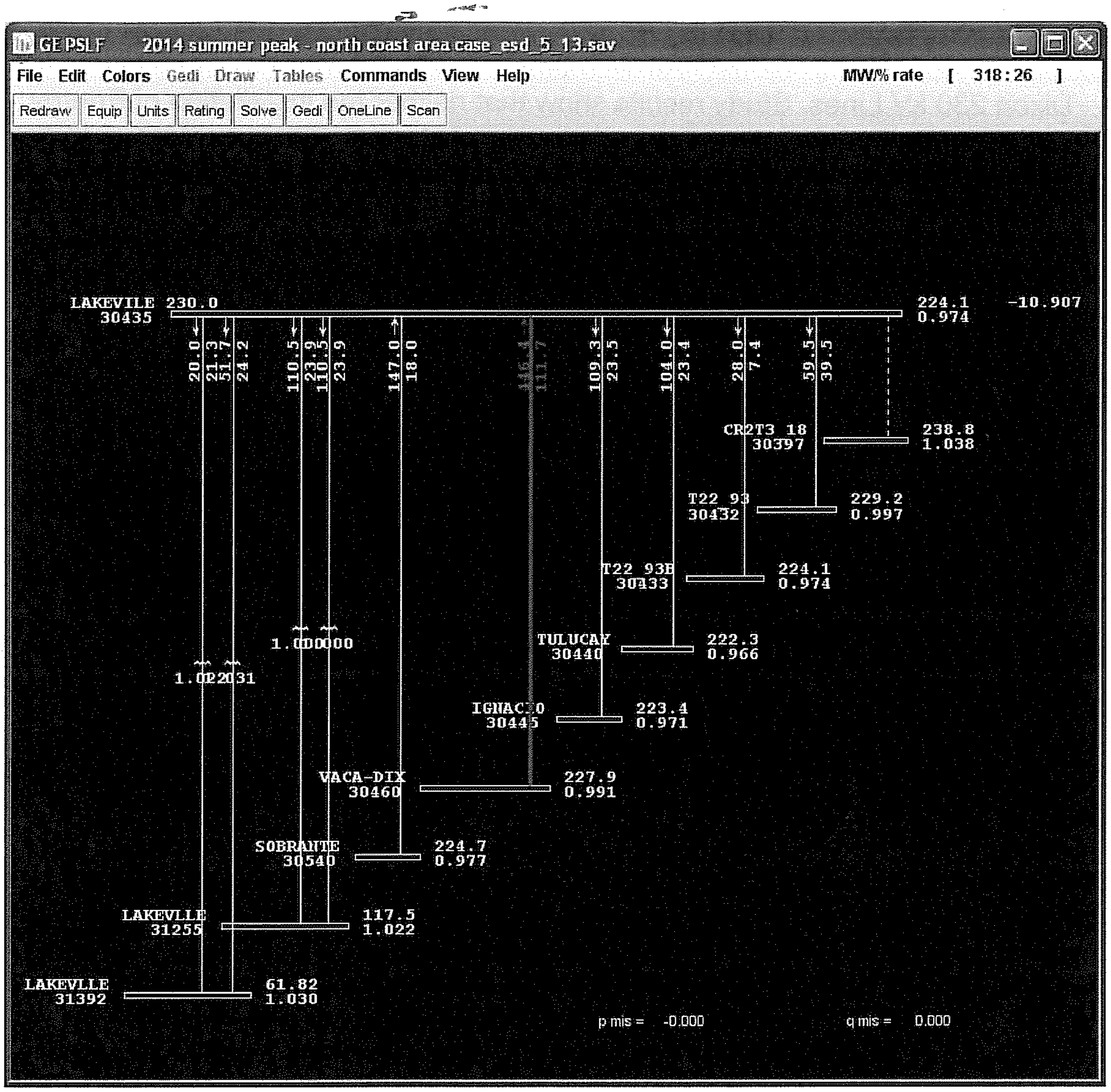


Figure 4 Overload on Vaca Dixon – Lakeville 230 kV line following the outages of Tulucay - Vaca Dixon and Geysers9 – Lakeville 230 kV lines as identified in 2010 ISO Transmission Plan

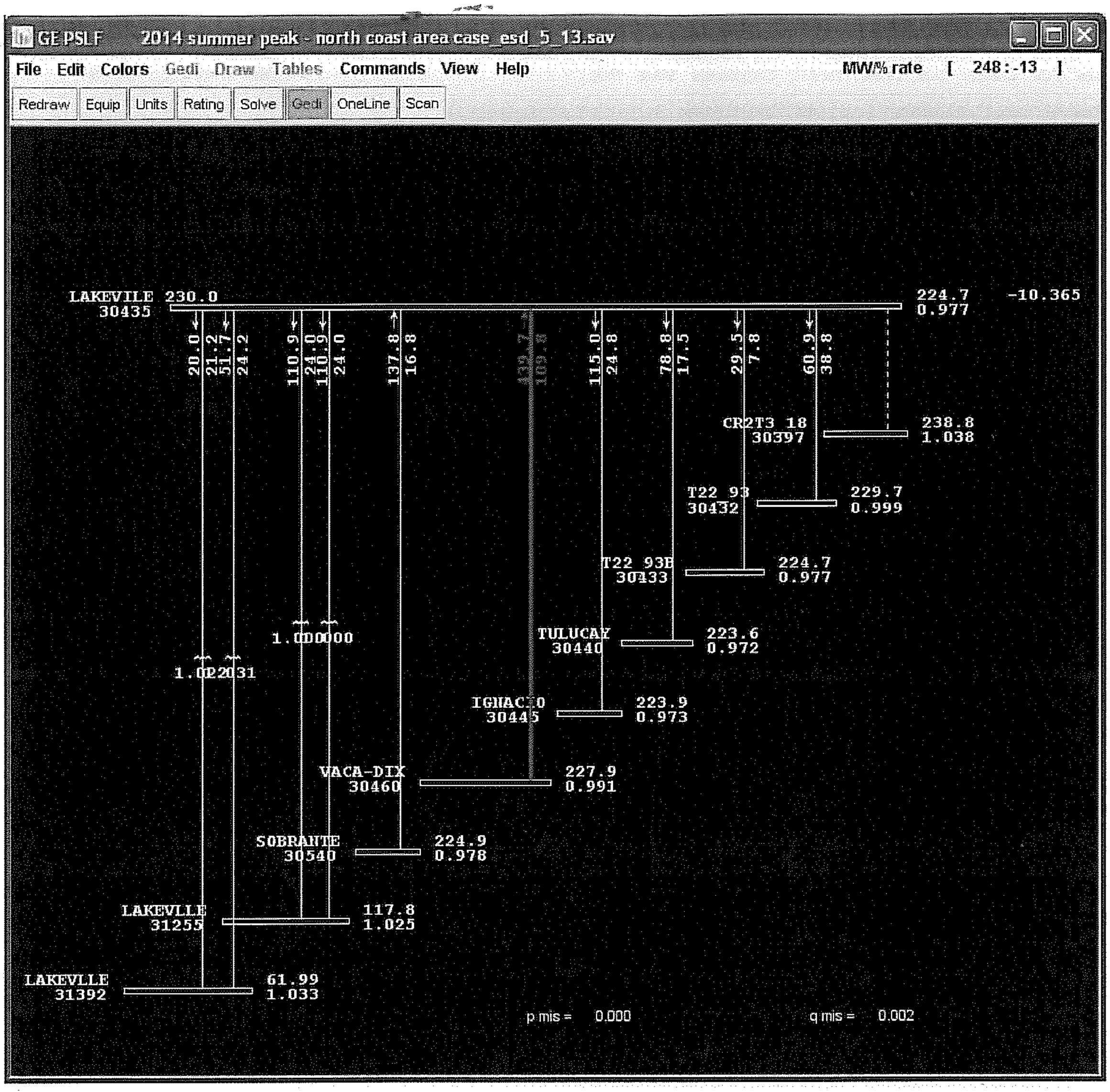


Figure 5 Overload on Vaca Dixon – – Lakeville 230 kV line following the outages of Tulucay - Vaca Dixon and Geysers9 – Lakeville 230 kV lines with a 25 MW Energy Storage at Tulucay 60 kV Bus

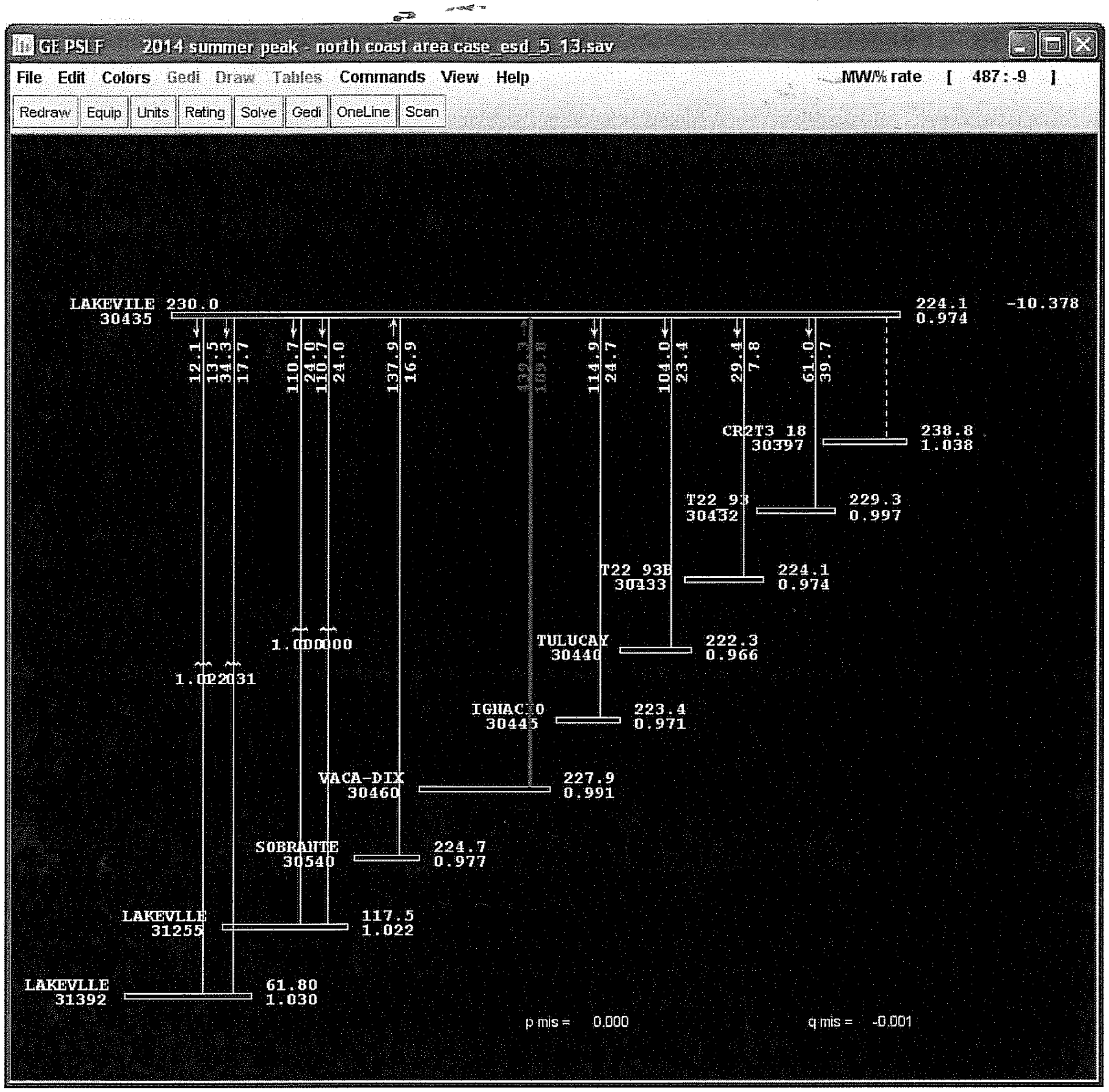


Figure 6 Overload on Vaca Dixon – Lakeville 230 kV line following the outages of Tulucay - Vaca Dixon and Geysers9 – Lakeville 230 kV lines with a 25 MW Energy Storage at Lakeville 60 kV Bus

38. Contrary to Ms. Mueller's claim, moving the Energy Storage Device from Tulucay to Lakeville does not eliminate the overload on both lines. I note that in its reliability study, the ISO inadvertently failed to reflect in its assumptions and model a reconductoring project previously approved by the ISO that

involved reconductoring of both the Vaca-Dixon-Tulucay and Vaca Dixon Lakeville lines. Regardless of whether the Energy Storage Device is placed at Tulucay or at Lakeville, overloads remain on both lines. Accordingly, even if the ISO were to approve installation of the Energy Storage Device, the previously approved project to reconductor the Vaca-Dixon-Tulucay and Vaca Dixon Lakeville lines would still need to proceed. Stated differently, installing an Energy Storage Device would still require both lines to be reconductored, and those costs would be incurred in addition to incurring the costs associated with installation of an Energy Storage Device.

39. Ms. Mueller claims that in the interim until the reconductoring project is completed, there is an operating procedure in place for the ISO to shed load in the event of the Category C contingencies identified in the Reliability Assessment. She is incorrect. The operating procedure merely involves opening of the parallel 230 kV line, and that will not result in load dropping. There are two 230 kV transmission lines connecting Vaca Dixon and Lakeville substations. During the period time before the reconductoring project is completed, following the loss of one 230 kV line, the operating procedure will open the parallel 230 kV line. This operating procedure will merely shift power flow in the area. It will not result in load dropping.

I hereby declare under the penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

____

Ponpranod Didsayabutra

ATTACHMENT A

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Cal Cement Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Cal Cement 66kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

An outage of the Antelope-Cal Cement 66kV line is projected to cause a voltage deviation of more than 11% at the Cal Cement 66kV substation. In addition the outage causes two thermal overloads. SCE is proposing a long term solution to rearrange the Antelope, Bailey, and WindHub systems into a radial configuration.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Cal Cement 66kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the low voltage issue described above.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required from SCE to complete their long term plan.TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print): **John Dizard**

Title: **Managing Member & CEO**

Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

<u>General Data</u>

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

<u>Technical Data</u>

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

<u>Planning Level Cost Data</u>

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

<u>Miscellaneous Data</u>

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

    As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

Identify Concern

An outage of the Antelope-Cal Cement 66kV line is projected to cause voltage deviations at the Cal Cement 66kV substation of more than 11%. In addition the outage also causes two thermal overloads.

Validate Study Results

TTS confirmed the reliability concern by performing a load flow study using the WECC 2011 base case. The contingency caused a 11.2% post transient voltage deviation at the Cal Cement 66kV substation. Tables 1a and 1b below outline these results.

Bus	Name	kV	Out_Name	Post Transient Voltage Deviation
24408	BREEZE	66	line_1	-0.112
24414	MONOLITH	66	line_1	-0.112
24428	CALCMENT	66	line_1	-0.112
24410	CUMMINGS	66	line_1	-0.107
24415	LORAINE	66	line_1	-0.107
24476	CORRECT	66	line_1	-0.104
24416	WALKERBN	66	line_1	-0.103
24436	GOLDTOWN	66	line_1	-0.103
24417	HAVILAH	66	line_1	-0.101
24456	BOREL	66	line_1	-0.097
24409	CORUM	66	line_1	-0.093
24429	GREATLKS	66	line_1	-0.074
24434	ROSAMOND	66	line_1	-0.074

Table 1a: Pre-Project Antelope-Cal Cement 66kV Line Contingency Results

Apply Solution

Installation of an ABB modular SVC rated at -40/+50MVAR at Cal Cement 66kV substation would eliminate the low voltage concern. A SVC was placed on the CALCMENT 66kV bus. The contingency caused no post transient voltage deviation. Tables 1b outline these results.

Bus	Name	kV	Out_Name	Post Transient Voltage Deviation
24408	BREEZE	66	line_1	-0.001
24414	MONOLITH	66	line_1	-0.001
24428	CALCMENT	66	line_1	0
24410	CUMMINGS	66	line_1	-0.004
24415	LORAINE	66	line_1	-0.001
24476	CORRECT	66	line_1	-0.005

24416	WALKERBN	66	line_1	-0.001
24436	GOLDTOWN	66	line_1	-0.004
24417	HAVILAH	66	line_1	-0.001
24456	BOREL	66	line_1	-0.001
24409	CORUM	66	line_1	-0.007
24429	GREATLKS	66	line_1	-0.009
24434	ROSAMOND	66	line_1	-0.009

Table 1b: Post-Project Antelope-Cal Cement 66kV Line Contingency Results

In addition to the voltage improvements, the SVC at Cal Cement would also eliminate two thermal overloads that result from the loss of the Antelope-Cal Cement 66kV line. Table 1c outlines these results.

Bus Name	*Bus Name*	*kV*	*ID (T)*	*Normal Rating Amps*	*Emergency Rating Amps*	*Pre-Proj*	*Post-Proj*	*Contingency Description*	*OL % Pre-Proj*
ANTELOPE	ROSAMOND	66	1	542	732	**606**	533.3	ANTELOPE - CALCMENT 66.0 kV #1	13.40%
LANCSTR	GOLDTOWN	66	1	450	610	**679.4**	**606.2**		16.28%
ROSAMOND	TAP 52	66	1	1075	1200	**1212.6**	1062.2		13.99%
ROSAMOND	TAP 71	66	1	605	820	**645.1**	567.2		12.87%

1c: Thermal Overload Benefits

General Data

SCE is proposing a long term solution to install radicalize the Antelope, Bailey, and WindHub systems. There is no identified in-service date and the final plan has not been completed.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Cal Cement 66kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required from SCE to complete their long term plan.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to SCE to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering SCE a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that SCE cannot offer. If

SCE would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution is in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

The network model used to perform this study was the WECC 2011 heavy spring base case which the CAISO has access to.

Please find the following technical data attached to this request:

- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
- Reliability and Maintainability Information (RAM_1JNR100004-713 REV 0.pdf)
- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF SVC model Parameter list.doc & PSLF 17 SVCWSC Model.pdf)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project

Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,361,800	$ 1,089,000	$ 660,000	$ 5,380,100	$ 3,260,966
1	$ 8,730,700	$ 1,801,143	$ 1,080,861	$ 864,339	$ 523,842	$ 4,270,185	$ 3,260,966
2	$ 6,929,557	$ 1,429,568	$ 857,879	$ 415,773	$ 415,773	$ 3,118,993	$ 3,260,966
3	$ 5,499,989	$ 1,134,648	$ 680,899	$ 66,000	$ 329,999	$ 2,211,546	$ 3,260,966
4	$ 4,365,341	$ 900,570	$ 152,787	$ 8,731	$ 261,920	$ 1,324,008	$ 3,260,966
						$ 16,304,832	

Ratemaking Assumptions	TTS Costs
TTS Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Depreciation	20.6%
Rate of Return	12.4%

The TTS project rates are highly competitive with SCE rates. Overall TTS rates are 9.1% less than those of SCE, as outlined below:

SCE Cost							
Estimated Cost to CAISO ratepayers for one FACTS device							
Year	Rate Base	Depreciation	ROE + Interest	O&M (Include Insurance)	A&G	Revenue Requirement	Levelized Revenue Req
0	$ 11.000.000	$ 2.036.100	$ 1,036,200	$ 2.220.900	$ 1,091,200	$ 6.384.400	$ 4.419.390
1	$ 8.963.900	$ 1,659,218	$ 844,399	$ 1.809.811	$ 889,219	$ 5.202.648	$ 4.419.390
2	$ 7.304.682	$ 1,352.097	$ 688,101	$ 1.474.815	$ 724,624	$ 4.239.637	$ 4.419.390
3	$ 5.952.585	$ 1,101.824	$ 560,734	$ 1.201.827	$ 590,496	$ 3.454.881	$ 4.419.390
4	$ 4.850.762	$ 897.876	$ 456,942	$ 979.369	$ 481,196	$ 2.815.382	$ 4,419.390
TOTAL						$ 22,096,948	

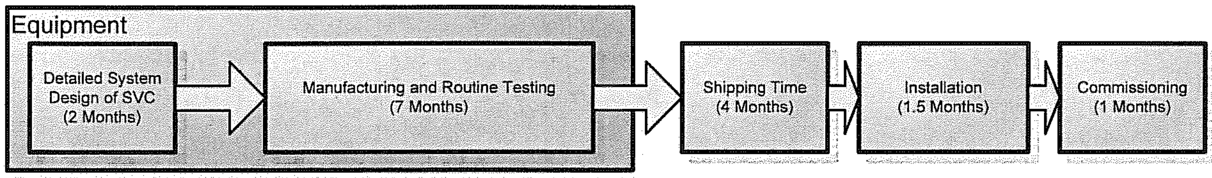
Ratemaking Assumptions	SCE Rates
TTS Capital Cost	11,000,000
O&M (include Insurance)	20.2%
A&G	9.9%
Depreciation	18.5%
Cost of Capital	9.4%

Preliminary analysis indicates that the TTS solution has a levelized annual revenue requirement of $3.3M compared to $4.4M for SCE. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

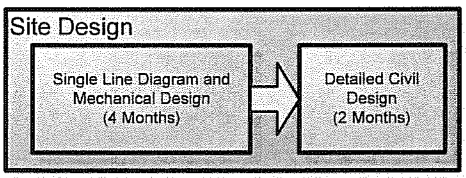
If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



During the 9 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under SCE supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: SCE and ABB (under SCE supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Camp Evers Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Camp Evers 115kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2008 Electric Transmission Grid Expansion Plan for the San Central Coast an outage on one of the following lines will cause low voltages at the Camp Evers 115kV substation:

- Green Valley-Rob Roy 115kV #1
- Green Valley-Rob Roy 115kV #2
- Green Valley-Camp Evers 115kV

PG&E lists a long term mitigation plan to rebuild the 7.5 mile Green Valley-Rob Roy 115kV line including new circuit breakers at Rob Roy. In addition, the plan calls for 20-30 MVARs of reactive support at Camp Evers.

Due to the lengthy approval process and long lead times required to complete this long term plan, Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Camp Evers 115kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan. TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes

Regional Transmission

California ISO

151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ____________________________________

Name (type or print): **John Dizard**

Title: **Managing Member & CEO**

Company Name: **Transmission Technology Solutions, LLC**
Street Address: **200 East 94th Street, Suite 2218**
City, State: **New York, NY**
Zip Code: **10128**
Phone Number: **917-282-0658**
Fax Number: **212-937-4622**
Email Address: **dizard@gmail.com**
Date: **12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

Technical Data

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

Planning Level Cost Data

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

  As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

General Data

As outlined in the PG&E 2008 Electric Transmission Grid Expansion Plan for the San Central Coast an outage on one of the following lines will cause low voltages at the Camp Evers 115kV substation:

- Green Valley-Rob Roy 115kV #1
- Green Valley-Rob Roy 115kV #2
- Green Valley-Camp Evers 115kV

PG&E lists a long term mitigation plan to rebuild the 7.5 mile Green Valley-Rob Roy 115kV line including new circuit breakers at Rob Roy. In addition, the plan calls for 20-30 MVARs of reactive support at Camp Evers.

Due to the lengthy approval process and long lead times required to complete this long term plan, Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Camp Evers 115kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution was in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

Please find the following technical data attached to this request:

- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
- Reliability and Maintainability Information (RAM_1JNR100004-713 REV 0.pdf)
- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF 17 SVCWSC Model.pdf & PSLF SVC model Parameter list.doc)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,364,000	$ 1,089,000	$ 660,000	$ 5,382,300	$ 3,262,253
1	$ 8,730,700	$ 1,801,143	$ 1,082,607	$ 864,339	$ 523,842	$ 4,271,932	$ 3,262,253
2	$ 6,929,557	$ 1,429,568	$ 859,265	$ 415,773	$ 415,773	$ 3,120,379	$ 3,262,253
3	$ 5,499,989	$ 1,134,648	$ 681,999	$ 66,000	$ 329,999	$ 2,212,646	$ 3,262,253
4	$ 4,365,341	$ 900,570	$ 152,787	$ 8,731	$ 261,920	$ 1,324,008	$ 3,262,253
						$ 16,311,264	

Ratemaking Assumptions	TTS Costs
TTS Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Depreciation	20.6%
Rate of Return	12.4%

The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 6.2% less than those of PG&E, as outlined below:

PG&E Cost (2008)							
Estimated Cost to CAISO ratepayers for one FACTS device							
Year	Rate Base	Depreciation	ROE + Interest	O&M (Include Insurance)	A&G	Revenue Requirement	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,023,000	$ 1,970,100	$ 803,000	$ 6,065,400	$ 4,028,042
1	$ 8,730,700	$ 1,801,143	$ 811,955	$ 1,563,668	$ 637,341	$ 4,814,108	$ 4,028,042
2	$ 6,929,557	$ 1,429,568	$ 644,449	$ 1,241,084	$ 505,858	$ 3,820,958	$ 4,028,042
3	$ 5,499,989	$ 1,134,648	$ 511,499	$ 985,048	$ 401,499	$ 3,032,694	$ 4,028,042
4	$ 4,365,341	$ 900,570	$ 405,977	$ 781,833	$ 318,670	$ 2,407,049	$ 4,028,042
TOTAL						$ 20,140,209	

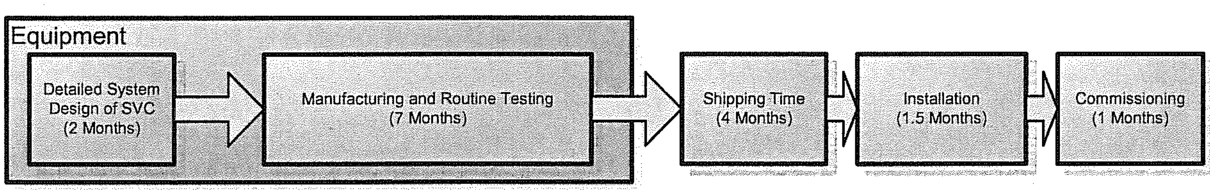
Ratemaking Assumptions	PG&E Rates
TTS Capital Cost	11,000,000
O&M (include Insurance)	17.9%
A&G	7.3%
Depreciation	20.6%
Cost of Capital	9.3%

Preliminary analysis indicates that the TTS solution has a levelized annual revenue requirement of $3.3M compared to $4.0M for PG&E. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

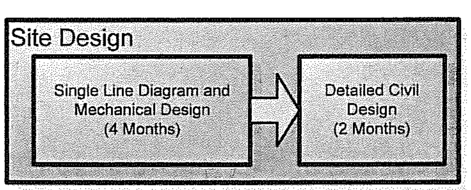
If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



During the 9 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Cottonwood Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Cottonwood 60kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the North Valley an outage of the Neo Red Bluff generator is projected to cause voltage deviations of more than 10% at the Tyler and Rawson 60kV substations.

PG&E lists that the mitigation plan is to install a UVLS; however there is no in-service date mentioned.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Cottonwood 60kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the voltage issue described above.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan. TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print): **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

Technical Data

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

Planning Level Cost Data

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

  As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

Identify Concern

As outlined in the assessment results for the North Valley an outage of the Neo Red Bluff generator is projected to cause voltage deviations of more than 10% at the Tyler and Rawson 60kV substations. PG&E lists that the mitigation plan is to install a UVLS.

Validate Study Results

TTS confirmed the reliability concern by performing a load flow study using the WECC 2011 base case 11hs1b.sav.Tyler's pre-contingency voltage magnitude was recorded at 1.058p.u. The contingency caused a 12% post transient voltage deviation that left Tyler's voltage magnitude at 0.928p.u. Tables 1a and 1b below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
31621	NEO REDB	13.8	30	303	1.05	1	base	11hs1b.sav
31605	NEO REDT	60	30	303	1.061	1	base	11hs1b.sav
31609	CR CANAL	60	30	303	1.057	1	base	11hs1b.sav
31610	TYLER	60	30	333	1.058	1	base	11hs1b.sav
31603	CANAL TP	60	30	303	1.058	1	base	11hs1b.sav
31611	RASN JNT	60	30	303	1.059	1	base	11hs1b.sav

Table 1a: Pre-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
31621	NEO REDB	13.8	30	303	0.907	1	gen_1	11hs1b.sav	14%
31605	NEO REDT	60	30	303	0.93	1	gen_1	11hs1b.sav	12%
31609	CR CANAL	60	30	303	0.927	1	gen_1	11hs1b.sav	12%
31610	TYLER	60	30	333	0.928	1	gen_1	11hs1b.sav	12%
31603	CANAL TP	60	30	303	0.928	1	gen_1	11hs1b.sav	12%
31611	RASN JNT	60	30	303	0.93	1	gen_1	11hs1b.sav	12%

Table 1b: Pre-Project Neo Red Bluff Generator Contingency Results

Apply Solution

Installation of a ABB modular SVC rated at -40/+50MVAR at the RASN JNT 60kV substation would eliminate the low voltage concern. A SVC was placed on the RASN JCT 60kV bus and Tyler's pre-contingency voltage magnitude was recorded at 1.057p.u. The contingency caused no post transient voltage deviation leaving Tyler's voltage magnitude at 1.057p.u. The output of the SVC post-contingency was recorded at +26.5MVAR. Tables 1c and 1d below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name

31621	NEO REDB	13.8	30	303	1.05	1	base	11hs1b_post_proj.sav
31605	NEO REDT	60	30	303	1.06	1	base	11hs1b_post_proj.sav
31609	CR CANAL	60	30	303	1.057	1	base	11hs1b_post_proj.sav
31610	TYLER	60	30	333	1.057	1	base	11hs1b_post_proj.sav
31603	CANAL TP	60	30	303	1.058	1	base	11hs1b_post_proj.sav
31611	RASN JNT	60	30	303	1.059	1	base	11hs1b_post_proj.sav
31621	NEO REDB	13.8	30	303	1.05	1	base	11hs1b_post_proj.sav
31605	NEO REDT	60	30	303	1.06	1	base	11hs1b_post_proj.sav
31609	CR CANAL	60	30	303	1.057	1	base	11hs1b_post_proj.sav
31610	TYLER	60	30	333	1.057	1	base	11hs1b_post_proj.sav
31603	CANAL TP	60	30	303	1.058	1	base	11hs1b_post_proj.sav
31611	RASN JNT	60	30	303	1.059	1	base	11hs1b_post_proj.sav

Table 1c: Post-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
31621	NEO REDB	13.8	30	303	1.033	1	gen_1	11hs1b_post_proj.sav	1.60%
31605	NEO REDT	60	30	303	1.059	1	gen_1	11hs1b_post_proj.sav	0.10%
31609	CR CANAL	60	30	303	1.057	100%	gen_1	11hs1b_post_proj.sav	0.00%
31610	TYLER	60	30	333	1.057	1	gen_1	11hs1b_post_proj.sav	0.00%
31603	CANAL TP	60	30	303	1.058	100%	gen_1	11hs1b_post_proj.sav	0.00%
31611	RASN JNT	60	30	303	1.059	1	gen_1	11hs1b_post_proj.sav	0.00%
31621	NEO REDB	13.8	30	303	1.033	1	gen_1	11hs1b_post_proj.sav	1.60%
31605	NEO REDT	60	30	303	1.059	1	gen_1	11hs1b_post_proj.sav	0.10%
31609	CR CANAL	60	30	303	1.057	100%	gen_1	11hs1b_post_proj.sav	0.00%
31610	TYLER	60	30	333	1.057	1	gen_1	11hs1b_post_proj.sav	0.00%
31603	CANAL TP	60	30	303	1.058	100%	gen_1	11hs1b_post_proj.sav	0.00%
31611	RASN JNT	60	30	303	1.059	1	gen_1	11hs1b_post_proj.sav	0.00%

Table 1d: Post-Project Neo Red Bluff Generator Contingency Results

General Data

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the North Valley an outage of the Neo Red Bluff generator is projected to cause voltage deviations of more than 10% at the Tyler and Rawson 60kV substations.

PG&E lists that the mitigation plan is to install a UVLS; however there is no in-service date mentioned.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Cottonwood 60kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the voltage issue described above.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution was in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

The network model used to perform this study was the WECC 2011 base case 11hs1b.sav

Please find the following technical data attached to this request:

- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
- Reliability and Maintainability Information (RAM_1JNR100004-713 REV 0.pdf)
- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF 17 SVCWSC Model.pdf & PSLF SVC model Parameter list.doc)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,364,000	$ 1,089,000	$ 660,000	$ 5,382,300	$ 3,262,253
1	$ 8,730,700	$ 1,801,143	$ 1,082,607	$ 864,339	$ 523,842	$ 4,271,932	$ 3,262,253
2	$ 6,929,557	$ 1,429,568	$ 859,265	$ 415,773	$ 415,773	$ 3,120,379	$ 3,262,253
3	$ 5,499,989	$ 1,134,648	$ 681,999	$ 66,000	$ 329,999	$ 2,212,646	$ 3,262,253
4	$ 4,365,341	$ 900,570	$ 152,787	$ 8,731	$ 261,920	$ 1,324,008	$ 3,262,253
						$ 16,311,264	

Ratemaking Assumptions	TTS Costs
TTS Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Depreciation	20.6%
Rate of Return	12.4%

The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 6.2% less than those of PG&E, as outlined below:

PG&E Cost (2008)							
Estimated Cost to CAISO ratepayers for one FACTS device							
Year	Rate Base	Depreciation	ROE + Interest	O&M (Include Insurance)	A&G	Revenue Requirement	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,023,000	$ 1,970,100	$ 803,000	$ 6,065,400	$ 4,028,042
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TOTAL						$ 20,140,209	

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TTS Capital Cost	11,000,000
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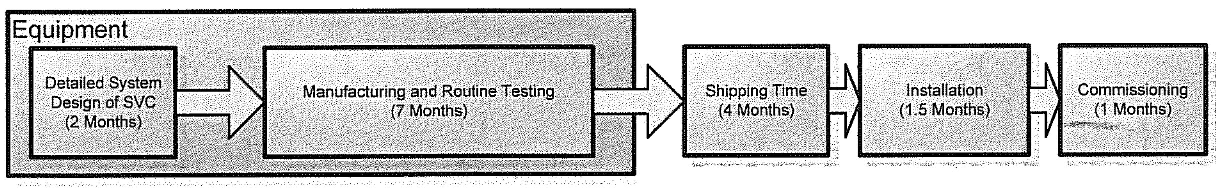
A&G	7.3%
Depreciation	20.6%
Cost of Capital	9.3%

Preliminary analysis indicates that the TTS solution has a levelized annual revenue requirement of $3.3M compared to $4.0M for PG&E. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

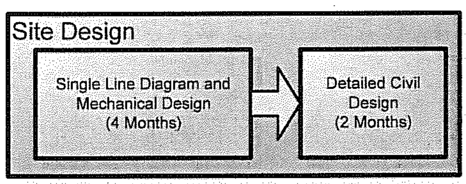
If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



During the 9 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Garberville Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Garberville 60kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the Humboldt Area an outage of the Garberville-Bridgeville 60kV line when Kekawaka is offline is projected to cause low voltages in the Garberville 60kV area.

There was an ISO approved project to replace an existing synchronous condenser with new reactive support device by May 2009. The latest PG&E 2008 Electric Transmission Grid Expansion Plan lists a later in-service date of May 2011.The voltage violation is apparent prior to this in-service date.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Garberville 60kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the low voltage issue described above.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan. TTS feels that the CAISO should have enough time to evaluate this project to determine what is most economical for ratepayers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11/ 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name:	**John Dizard**
Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print): **John Dizard**

Title: **Managing Member & CEO**

Company Name: **Transmission Technology Solutions, LLC**

Street Address: **200 East 94th Street, Suite 2218**

City, State: **New York, NY**

Zip Code: **10128**

Phone Number: **917-282-0658**

Fax Number: **212-937-4622**

Email Address: **dizard@gmail.com**

Date: **12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

Technical Data

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

Planning Level Cost Data

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

  As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

Identify Concern

As outlined in the assessment results for the Humboldt Area an outage of the Garberville-Bridgeville 60kV line when Kekawaka is offline is projected to cause low voltages in the Garberville 60kV area.

Validate Study Results

TTS confirmed the reliability concern by performing a load flow study using the WECC 2008 base case 08hs4a.sav. Garberville's pre-contingency voltage magnitude was recorded at 0.942p.u. The contingency caused a 21% post transient voltage deviation that left Garberville's voltage magnitude at 0.74p.u. Tables 1a and 1b below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
31116	GRBRVLLE	60	30	301	0.942	1	base	08hs4a.sav
31118	KEKAWAKA	60	30	301	0.951	1	base	08hs4a.sav
31166	KEKAWAK	4.16	30	391	0.891	1	base	08hs4a.sav
31310	COVELO6	60	30	302	0.974	1	base	08hs4a.sav
31308	LYTNVLLE	60	30	302	0.98	1	base	08hs4a.sav

Table 1a: Pre-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
31116	GRBRVLLE	60	30	301	0.74	1	line_1	08hs4a.sav	21.00%
31118	KEKAWAKA	60	30	301	0.77	1	line_1	08hs4a.sav	19.00%
31166	KEKAWAK	4.16	30	391	0.722	1	line_1	08hs4a.sav	19.00%
31310	COVELO6	60	30	302	0.872	1	line_1	08hs4a.sav	10.00%
31308	LYTNVLLE	60	30	302	0.879	1	line_1	08hs4a.sav	10.00%

Table 1b: Pre-Project Garberville-Bridgeville 60kV Line Contingency Results

Apply Solution

Installation of a ABB modular SVC rated at -40/+50MVAR at Garberville 60kV substation would eliminate the low voltage concern. A SVC was placed on the GRBRVLLE 60kV bus and the pre-contingency voltage magnitude was recorded at 0.942p.u. The contingency caused no post transient voltage deviation leaving Garberville's voltage magnitude at 0.942p.u. The output of the SVC post-contingency was recorded at +9.2MVAR. Tables 1c and 1d below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
31116	GRBRVLLE	60	30	301	0.942	1	base	08hs4a_post_proj.sav
31118	KEKAWAKA	60	30	301	0.951	1	base	08hs4a_post_proj.sav

31166	KEKAWAK	4.16	30	391	0.891	1	base	08hs4a_post_proj.sav
31310	COVELO6	60	30	302	0.974	1	base	08hs4a_post_proj.sav
31308	LYTNVLLE	60	30	302	0.98	1	base	08hs4a_post_proj.sav

Table 1c: Post-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
31116	GRBRVLLE	60	30	301	0.942	1	line_1	08hs4a_post_proj.sav	0.00%
31118	KEKAWAKA	60	30	301	0.946	1	line_1	08hs4a_post_proj.sav	0.53%
31166	KEKAWAK	4.16	30	391	0.887	1	line_1	08hs4a_post_proj.sav	0.45%
31310	COVELO6	60	30	302	0.961	1	line_1	08hs4a_post_proj.sav	1.33%
31308	LYTNVLLE	60	30	302	0.968	1	line_1	08hs4a_post_proj.sav	1.22%

Table 1d: Post-Project Garberville-Bridgeville 60kV Line Contingency Results

General Data

There was an ISO approved project to replace an existing synchronous condenser with new reactive support device by May 2009. The latest PG&E 2008 Electric Transmission Grid Expansion Plan lists a later in-service date of May 2011.The voltage violation is apparent prior to this in-service date.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Garberville 60kV substation by October 2010. This interim solution is necessary for system reliability while PG&E implements their long term solution.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan. TTS feels that the CAISO should have enough time to evaluate this project to determine what is most economical for ratepayers.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution was in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.

- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

The network model used to perform this study was the WECC 2008 base case 08hs4a.sav.

Please find the following technical data attached to this request:
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- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF 17 SVCWSC Model.pdf & PSLF SVC model Parameter list.doc)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,364,000	$ 1,089,000	$ 660,000	$ 5,382,300	$ 3,262,253
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The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 6.2% less than those of PG&E, as outlined below:

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Estimated Cost to CAISO ratepayers for one FACTS device							
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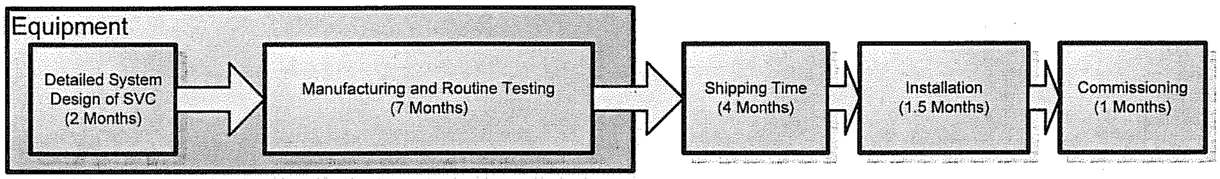
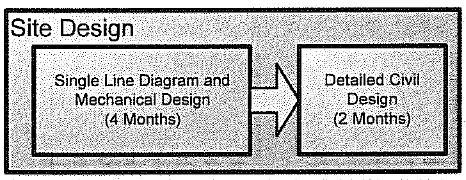
If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



During the 9 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Maple Creek Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Maple Creek 60kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the Humboldt Area an outage of the Humboldt-Maple Creek 60kV line is projected to cause low voltages in the Maple Creek and Hoopa substations.

PG&E is proposing a long term solution to install 10 MVARs of reactive support at Maple Creek Substation by May 2011. The voltage violation is apparent prior to this in-service date.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Maple Creek 60kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the low voltage issue described above.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required from PG&E to complete their long term plan.TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**1 0/ 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print):	**John Dizard**
Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

Technical Data

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

Planning Level Cost Data

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

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- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
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- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

  As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

Identify Concern

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the Humboldt Area an outage of the Humboldt-Maple Creek 60kV line is projected to cause low voltages in the Maple Creek and Hoopa substations.

Validate Study Results

TTS confirmed the reliability concern by performing a load flow study using the WECC 2008 base case 08hs4a.sav. Maple Creek's pre-contingency voltage magnitude was recorded at 1.004p.u. The contingency caused a 20% post transient voltage deviation that left Maple Creek's voltage magnitude at 0.808p.u. Tables 1a and 1b below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
31098	HOOPA	60	30	301	0.95	1	base	08hs4a.sav
31096	WILLWCRK	60	30	301	0.965	1	base	08hs4a.sav
31094	RUSS RCH	60	30	301	0.995	1	base	08hs4a.sav
31092	MPLE CRK	60	30	301	1.004	1	base	08hs4a.sav
31091	RDGE CBN	60	30	301	1.013	1	base	08hs4a.sav
31095	HYAMPOM	60	30	303	1.017	1	base	08hs4a.sav
31093	HYMPOMJT	60	30	303	1.018	1	base	08hs4a.sav
31554	GROUSCRK	60	30	303	1.018	1	base	08hs4a.sav
31850	CEDR FL+	9.11	30	391	1.018	1	base	08hs4a.sav
31553	BIG BAR	60	30	303	1.025	1	base	08hs4a.sav

Table 1a: Pre-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
31098	HOOPA	60	30	301	0.735	1	line_1	08hs4a.sav	23%
31096	WILLWCRK	60	30	301	0.755	1	line_1	08hs4a.sav	22%
31094	RUSS RCH	60	30	301	0.795	1	line_1	08hs4a.sav	20%
31092	MPLE CRK	60	30	301	0.808	1	line_1	08hs4a.sav	20%
31091	RDGE CBN	60	30	301	0.857	1	line_1	08hs4a.sav	15%
31095	HYAMPOM	60	30	303	0.888	1	line_1	08hs4a.sav	13%
31093	HYMPOMJT	60	30	303	0.889	1	line_1	08hs4a.sav	13%
31554	GROUSCRK	60	30	303	0.89	1	line_1	08hs4a.sav	13%
31850	CEDR FL+	9.11	30	391	0.89	1	line_1	08hs4a.sav	13%
31553	BIG BAR	60	30	303	0.946	1	line_1	08hs4a.sav	8%

Table 1b: Pre-Project Humboldt-Maple Creek 60kV Line Contingency Results

Apply Solution

Installation of an ABB modular SVC rated at -40/+50MVAR at Maple Creek 60kV substation would eliminate the low voltage concern. A SVC was placed on the MPLE CRK 60kV bus and the pre-contingency voltage magnitude was recorded at 1.0p.u. The contingency caused no post transient voltage deviation leaving Garberville's voltage magnitude at 1.0.u. The output of the SVC post-contingency was recorded at +8.4MVAR. Tables 1c and 1d below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
31098	HOOPA	60	30	301	0.945	1	base	08hs4a_post_proj.sav
31096	WILLWCRK	60	30	301	0.96	1	base	08hs4a_post_proj.sav
31094	RUSS RCH	60	30	301	0.991	1	base	08hs4a_post_proj.sav
31092	MPLE CRK	60	30	301	1	1	base	08hs4a_post_proj.sav
31091	RDGE CBN	60	30	301	1.01	1	base	08hs4a_post_proj.sav
31095	HYAMPOM	60	30	303	1.016	1	base	08hs4a_post_proj.sav
31093	HYMPOMJT	60	30	303	1.016	1	base	08hs4a_post_proj.sav
31554	GROUSCRK	60	30	303	1.016	1	base	08hs4a_post_proj.sav
31850	CEDR FL+	9.11	30	391	1.016	1	base	08hs4a_post_proj.sav
31553	BIG BAR	60	30	303	1.026	1	base	08hs4a_post_proj.sav

Table 1c: Post-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
31098	HOOPA	60	30	301	0.945	1	line_1	08hs4a_post_proj.sav	0%
31096	WILLWCRK	60	30	301	0.96	1	line_1	08hs4a_post_proj.sav	0%
31094	RUSS RCH	60	30	301	0.991	1	line_1	08hs4a_post_proj.sav	0.00%
31092	MPLE CRK	60	30	301	1	1	line_1	08hs4a_post_proj.sav	0.00%
31091	RDGE CBN	60	30	301	1.005	1	line_1	08hs4a_post_proj.sav	0.50%
31095	HYAMPOM	60	30	303	1.01	1	line_1	08hs4a_post_proj.sav	0.59%
31093	HYMPOMJT	60	30	303	1.01	1	line_1	08hs4a_post_proj.sav	0.59%
31554	GROUSCRK	60	30	303	1.01	1	line_1	08hs4a_post_proj.sav	0.59%
31850	CEDR FL+	9.11	30	391	1.01	1	line_1	08hs4a_post_proj.sav	0.59%
31553	BIG BAR	60	30	303	1.021	1	line_1	08hs4a_post_proj.sav	0.49%

Table 1d: Post-Project Humboldt-Maple Creek 60kV Line Contingency Results

General Data

PG&E is proposing a long term solution to install 10 MVARs of reactive support at Maple Creek Substation by May 2011. The voltage violation is apparent prior to this in-service date.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Maple Creek 60kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required from PG&E to complete their long term plan.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution is in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

The network model used to perform this study was the WECC 2008 base case 08hs4a.sav which the CAISO has access to.

Please find the following technical data attached to this request:

- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
- Reliability and Maintainability Information (RAM_1JNR100004-713 REV 0.pdf)
- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF SVC model Parameter list.doc & PSLF 17 SVCWSC Model.pdf)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,364,000	$ 1,089,000	$ 660,000	$ 5,382,300	$ 3,262,253
1	$ 8,730,700	$ 1,801,143	$ 1,082,607	$ 864,339	$ 523,842	$ 4,271,932	$ 3,262,253
2	$ 6,929,557	$ 1,429,568	$ 859,265	$ 415,773	$ 415,773	$ 3,120,379	$ 3,262,253
3	$ 5,499,989	$ 1,134,648	$ 681,999	$ 66,000	$ 329,999	$ 2,212,646	$ 3,262,253
4	$ 4,365,341	$ 900,570	$ 152,787	$ 8,731	$ 261,920	$ 1,324,008	$ 3,262,253
						$ 16,311,264	

Ratemaking Assumptions	TTS Costs
TTS Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Depreciation	20.6%
Rate of Return	12.4%

The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 6.2% less than those of PG&E, as outlined below:

PG&E Cost (2008)							
Estimated Cost to CAISO ratepayers for one FACTS device							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Requirement	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,023,000	$ 1,970,100	$ 803,000	$ 6,065,400	$ 4,028,042
1	$ 8,730,700	$ 1,801,143	$ 811,955	$ 1,563,668	$ 637,341	$ 4,814,108	$ 4,028,042
2	$ 6,929,557	$ 1,429,568	$ 644,449	$ 1,241,084	$ 505,858	$ 3,820,958	$ 4,028,042
3	$ 5,499,989	$ 1,134,648	$ 511,499	$ 985,048	$ 401,499	$ 3,032,694	$ 4,028,042
4	$ 4,365,341	$ 900,570	$ 405,977	$ 781,833	$ 318,670	$ 2,407,049	$ 4,028,042
TOTAL						$ 20,140,209	

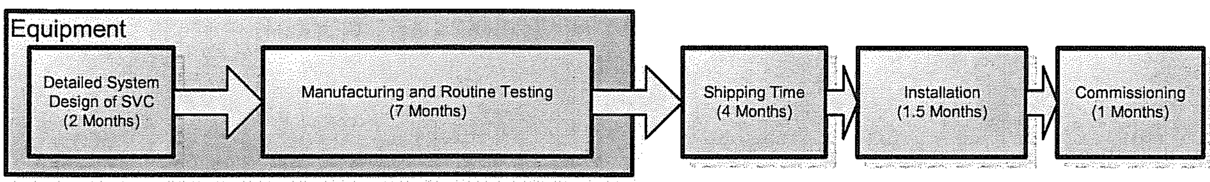
Ratemaking Assumptions	PG&E Rates
TTS Capital Cost	11,000,000
O&M (include Insurance)	17.9%
A&G	7.3%
Depreciation	20.6%
Cost of Capital	9.3%

Preliminary analysis indicates that the TTS solution has a levelized annual revenue requirement of $3.3M compared to $4.0M for PG&E. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

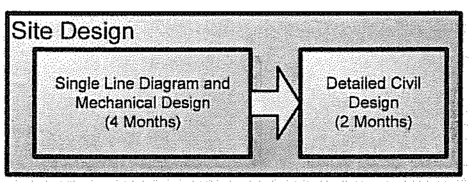
If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



During the 9 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Old River Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Old River 70kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2008 Electric Transmission Grid Expansion Plan for the San Joaquin and Los Padres areas an outage of one of the following lines will cause low voltages at Panama and Old River 70kV Substations:

- Kern-Old River 70kV #1
- Kern-Old River 70kV #2

PG&E lists a long term mitigation plan to reconductor 35 miles of the Kern-Old River 70kV lines.

Due to the lengthy approval process and long lead times required to complete this long term plan, Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Old River 70kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan. TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print):	**John Dizard**
Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
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CAISO TRANSMISSION PLANNING PROCESS

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- Evidence of securing the route or the ability to secure the route

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- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

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Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
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- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
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- Any additional miscellaneous data that may be applicable

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Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

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Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

  As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

Identify Concern

As outlined in the PG&E 2008 electric Transmission Grid Expansion Plan for the San Joaquin Valley and Los Padres areas an outage of either Kern-Old River #1 or #2 line is projected to cause voltage concerns in the Panama and Old River 70kV substations.

Validate Study Results

TTS confirmed the reliability concern by performing a load flow study using the WECC 2010 base case 10hs2sa.sav; however Kern (zone 315) had to be scaled to a level of 2050MW to produce low voltages at Old River. Old Rivers's pre-contingency voltage magnitude was recorded at 0.98p.u. The contingency caused a 7.6% post transient voltage deviation that left Old Rivers's voltage magnitude at 0.90p.u. Tables 1a and 1b below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
34904	OLD RIVR	70	30	315	0.9796	1	base	10hs2sa_pre_proj.sav
34882	SAN EMDO	70	30	315	0.9731	1	base	10hs2sa_pre_proj.sav
34868	COPUS	70	30	315	0.9648	1	base	10hs2sa_pre_proj.sav
34905	UNIONJCT	70	30	315	0.9899	1	base	10hs2sa_pre_proj.sav
34862	MARICOPA	70	30	315	0.9774	1	base	10hs2sa_pre_proj.sav
34906	PANAMA	70	30	315	0.9923	1	base	10hs2sa_pre_proj.sav

Table 1a: Pre-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
34904	OLD RIVR	70	30	315	0.9049	1	line_1	10hs2sa_pre_proj.sav	7.6%
34882	SAN EMDO	70	30	315	0.914	1	line_1	10hs2sa_pre_proj.sav	6.1%
34868	COPUS	70	30	315	0.927	1	line_1	10hs2sa_pre_proj.sav	3.9%
34905	UNIONJCT	70	30	315	0.9579	1	line_1	10hs2sa_pre_proj.sav	3.2%
34862	MARICOPA	70	30	315	0.9563	1	line_1	10hs2sa_pre_proj.sav	2.2%

Table 1b: Pre-Project Kern-Old River 70kV Line Contingency Results

Apply Solution

Installation of an ABB modular SVC rated at -40/+50MVAR at Old River 70kV substation would eliminate the low voltage concern. A SVC was placed on the OLD RIVR 70kV bus and the pre-contingency voltage magnitude was recorded at 0.98p.u. The contingency caused no post transient voltage. The output of the SVC post-contingency was recorded at +27MVAR. Tables 1c and 1d below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
34904	OLD RIVR	70	30	315	0.9796	1	base	10hs2sa_post_proj.sav

34882	SAN EMDO	70	30	315	0.9732	1	base	10hs2sa_post_proj.sav
34868	COPUS	70	30	315	0.9648	1	base	10hs2sa_post_proj.sav
34905	UNIONJCT	70	30	315	0.9899	1	base	10hs2sa_post_proj.sav
34862	MARICOPA	70	30	315	0.9775	1	base	10hs2sa_post_proj.sav

Table 1c: Post-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
34904	OLD RIVR	70	30	315	0.9796	1	line_1	10hs2sa_post_proj.sav	0.0%
34882	SAN EMDO	70	30	315	0.9732	1	line_1	10hs2sa_post_proj.sav	0.0%
34868	COPUS	70	30	315	0.9664	1	line_1	10hs2sa_post_proj.sav	-0.2%
34905	UNIONJCT	70	30	315	0.9966	1	line_1	10hs2sa_post_proj.sav	-0.7%
34862	MARICOPA	70	30	315	0.981	1	line_1	10hs2sa_post_proj.sav	-0.4%

Table 1d: Post-Project Kern-Old River 70kV Line Contingency Result

General Data

As outlined in the PG&E 2008 Electric Transmission Grid Expansion Plan for the San Joaquin and Los Padres areas an outage of one of the following lines will cause low voltages at Panama and Old River 70kV Substations:

- Kern-Old River 70kV #1
- Kern-Old River 70kV #2

PG&E lists a long term mitigation plan to reconductor 35 miles of the Kern-Old River 70kV lines.

Due to the lengthy approval process and long lead times required to complete this long term plan, Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Old River 70kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution was in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

Please find the following technical data attached to this request:

- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
- Reliability and Maintainability Information (RAM_1JNR100004-713 REV 0.pdf)
- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF 17 SVCWSC Model.pdf & PSLF SVC model Parameter list.doc)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project

Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 495,000	$ 1,182,500	$ 1,089,000	$ 660,000	$ 3,426,500	$ 3,162,665
1	$ 10,505,000	$ 495,000	$ 1,129,288	$ 1,039,995	$ 630,300	$ 3,294,583	$ 3,162,665
2	$ 10,010,000	$ 495,000	$ 1,076,075	$ 990,990	$ 600,600	$ 3,162,665	$ 3,162,665
3	$ 9,515,000	$ 495,000	$ 1,022,863	$ 941,985	$ 570,900	$ 3,030,748	$ 3,162,665
4	$ 9,020,000	$ 495,000	$ 969,650	$ 892,980	$ 541,200	$ 2,898,830	$ 3,162,665
						$ 15,813,325	

Ratemaking Assumptions	TTS Costs
Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Cost of Capital	10.75%

The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 7.82% less than those of PG&E, as outlined below:

PG&E Cost							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 495,000	$ 1,019,700	$ 1,969,000	$ 803,000	$ 4,286,700	$ 3,945,447
1	$ 10,505,000	$ 495,000	$ 973,814	$ 1,880,395	$ 766,865	$ 4,116,074	$ 3,945,447
2	$ 10,010,000	$ 495,000	$ 927,927	$ 1,791,790	$ 730,730	$ 3,945,447	$ 3,945,447
3	$ 9,515,000	$ 495,000	$ 882,041	$ 1,703,185	$ 694,595	$ 3,774,821	$ 3,945,447
4	$ 9,020,000	$ 495,000	$ 836,154	$ 1,614,580	$ 658,460	$ 3,604,194	$ 3,945,447
						$ 19,727,235	

Ratemaking Assumptions	PG&E Costs
Capital Cost	11,000,000
O&M (include Insurance)	17.9%
A&G	7.3%
Cost of Capital	9.27%

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

According to PG&E's service life analysis, this category of assets generally has a service life of 20 to 25 years with historical analysis showing that the average service life is slightly decreasing. Other electric utilities use service lives between 25 and 35 years for these types of assets at substations. PG&E proposes using an average service life of 25 years.

PG&E consistently uses negative rates for net salvage. While PG&E notes there is a trend of decreasing costs of removal, gross salvage is negligible and most retired equipment is not capable of being reused. For most retirements, the removal cost is much higher than the gross salvage receipt, resulting in negative net salvage. This is particularly the case where extensive labor is involved in removal or where California environmental laws require costly disposal. The range of estimates used in the electric industry is 5.00% to negative 20.00%. Therefore, PG&E proposes changing its current net salvage rate from negative 1.00% to negative 5.00%.

In contrast to the calculations used by PG&E, TTS is proposes using a service life of 20 years and a net salvage rate of 10.00% based on distinguishing characteristics of the facts which unlike those assets in the relevant PG&E account, involves a case of first impression not necessarily related to its historical data. The device is designed and intended to be both movable and easily removed. Because the device is movable, it is likely to have a slightly diminished service life of 20 years, in contrast to PG&E's assets with a service life of 25 years. Because the device is also designed to be easily removed with minimal labor, the main factor causing negative net salvage rates for PG&E's assets discussed above does not apply and therefore the net salvage rate is positive.

TTS will be using a 50/50 debt equity structure. The TTS cost of capital was derived by taking PG&E's published debt cost plus 2% plus return on equity (ROE) of 13.5%, then dividing by two. PG&E's debt cost was found in their current transmission owner rate case which was filed with the FERC. The following formula explains the method used to derive TTS cost of capital:

$$\frac{PTO\_DebtCost + 2\%}{2} + \frac{ReturnOnEquity}{2} = \frac{6\% + 2\%}{2} + \frac{13.5\%}{2} = 10.75\%$$

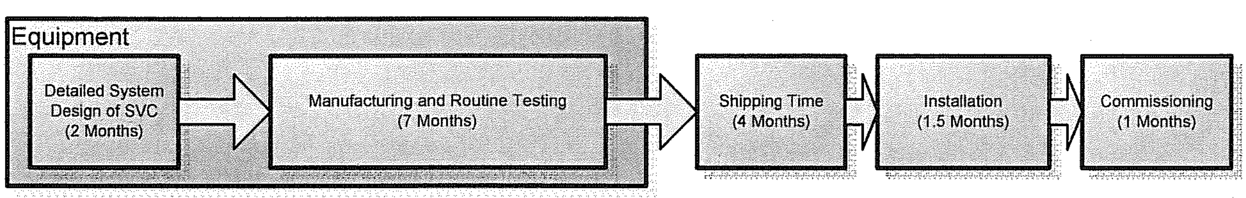
TTS's debt cost is based on taking the cost of capital of the PTO to which its equipment is connected, and adding 200 basis points. TTS is raising debt on a secured basis. Therefore, TTS will pass through debt service payments from the service contract revenues, to a bank lockbox arrangement, and then to the lender. The credit risk the lender is assuming is, therefore, the credit risk of the PTO. To their debt cost TTS will add 200 basis points (we would be negotiating for a lower number), to account for the "liquidity premium" that a non-rated entity would pay over and above the PTO debt cost. The equity cost of capital is based on returns previously awarded merchant transmission projects in California; that is, the Trans-Bay Cable and Path 15.

Using the assumptions listed above, our analysis indicates that the TTS solution has a levelized annual revenue requirement of $3.2M compared to $3.9M for PG&E. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

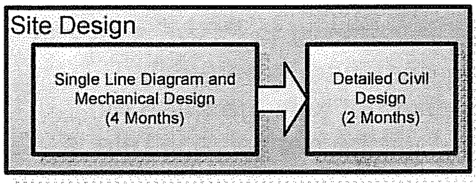
If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



During the 9 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Shepherd Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Shepherd 115kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2008 Electric Transmission Grid Expansion Plan for the San Joaquin and Los Padres areas an outage of the Herndon-Woodward 115kV line overlapping with the Kerckhoff Generator offline will cause low voltages at Shepherd and Woodward 115kV substations.

PG&E lists a long term mitigation plan to loop Shepherd 115kV substation into the Kerckhoff-Clovis-Sanger #1 115kV Line. In addition, the plan calls for 50MVARs of shunt capacitors at Shepherd Substation.

Due to the lengthy approval process and long lead times required to complete this long term plan, Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Old River 70kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan. TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print):	**John Dizard**
Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

Technical Data

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

Planning Level Cost Data

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

<u>General Data</u>

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

<u>Technical Data</u>

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

    As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

General Data

As outlined in the PG&E 2008 Electric Transmission Grid Expansion Plan for the San Joaquin and Los Padres areas an outage of the Herndon-Woodward 115kV line overlapping with the Kerckhoff Generator offline will cause low voltages at Shepherd and Woodward 115kV substations.

PG&E lists a long term mitigation plan to loop Shepherd 115kV substation into the Kerckhoff-Clovis-Sanger #1 115kV Line. In addition, the plan calls for 50MVARs of shunt capacitors at Shepherd Substation.

Due to the lengthy approval process and long lead times required to complete this long term plan, Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Old River 70kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution was in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

Please find the following technical data attached to this request:

- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
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- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF SVC model Parameter list.doc & PSLF 17 SVCWSC Model.pdf)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,364,000	$ 1,089,000	$ 660,000	$ 5,382,300	$ 3,262,253
1	$ 8,730,700	$ 1,801,143	$ 1,082,607	$ 864,339	$ 523,842	$ 4,271,932	$ 3,262,253
2	$ 6,929,557	$ 1,429,568	$ 859,265	$ 415,773	$ 415,773	$ 3,120,379	$ 3,262,253
3	$ 5,499,989	$ 1,134,648	$ 681,999	$ 66,000	$ 329,999	$ 2,212,646	$ 3,262,253
4	$ 4,365,341	$ 900,570	$ 152,787	$ 8,731	$ 261,920	$ 1,324,008	$ 3,262,253
						$ 16,311,264	

Ratemaking Assumptions	TTS Costs
TTS Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Depreciation	20.6%
Rate of Return	12.4%

The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 6.2% less than those of PG&E, as outlined below:

PG&E Cost (2008)							
Estimated Cost to CAISO ratepayers for one FACTS device							
Year	Rate Base	Depreciation	ROE + Interest	O&M (Include Insurance)	A&G	Revenue Requirement	Levelized Revenue Req
0	$ 11,000,000	$ 2,269,300	$ 1,023,000	$ 1,970,100	$ 803,000	$ 6,065,400	$ 4,028,042
1	$ 8,730,700	$ 1,801,143	$ 811,955	$ 1,563,668	$ 637,341	$ 4,814,108	$ 4,028,042
2	$ 6,929,557	$ 1,429,568	$ 644,449	$ 1,241,084	$ 505,858	$ 3,820,958	$ 4,028,042
3	$ 5,499,989	$ 1,134,648	$ 511,499	$ 985,048	$ 401,499	$ 3,032,694	$ 4,028,042
4	$ 4,365,341	$ 900,570	$ 405,977	$ 781,833	$ 318,670	$ 2,407,049	$ 4,028,042
TOTAL						$ 20,140,209	

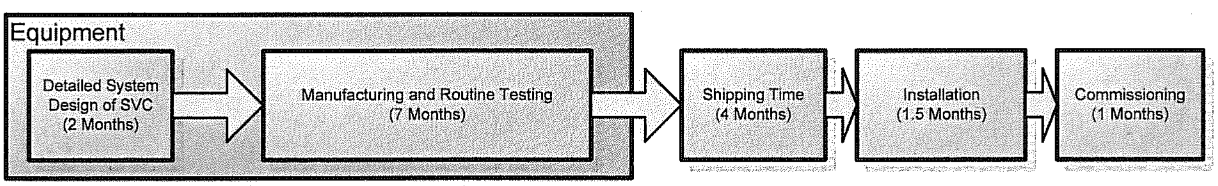
Ratemaking Assumptions	PG&E Rates
TTS Capital Cost	11,000,000
O&M (include Insurance)	17.9%
A&G	7.3%
Depreciation	20.6%
Cost of Capital	9.3%

Preliminary analysis indicates that the TTS solution has a levelized annual revenue requirement of $3.3M compared to $4.0M for PG&E. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

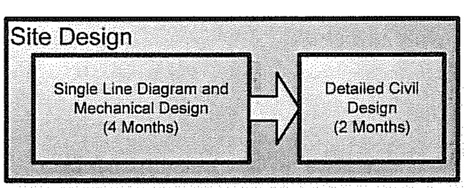
If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



During the 9 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.

- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Trinity Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Trinity 60kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the North Valley an outage of the Trinity 115/60kV transformer is projected to cause low voltages in the Trinity 60kV area.

PG&E lists that the mitigation plan is to transfer a portion of the 60kV loads to the Trinity-Maple Creek 60kV line if necessary. There is also mention of installing a UVLS; however there is no in-service date mentioned.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Trinity 60kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the low voltage issue described above.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan. TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print):	**John Dizard**
Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

Technical Data

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

Planning Level Cost Data

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

    As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

Identify Concern

As outlined in the assessment results for the North Valley an outage of the Trinity 115/60kV transformer is projected to cause low voltages in the Trinity 60kV area. PG&E lists that the mitigation plan is to install a UVLS.

Validate Study Results

ZGlobal confirmed the reliability concern by performing a load flow study using the WECC 2010 base case 10hs2sa.sav.The outage of the Trinity 115/60kV transformer had the greatest effect on the Hayfork 60kV bus. Hayfork's pre-contingency voltage magnitude was recorded at 0.955p.u. The contingency caused an 18% post transient voltage deviation that left Hayfork's voltage magnitude at 0.0.779p.u. Tables 1a and 1b below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
31560	HAYFORK	60	30	303	0.955	1	base	10hs2sa.sav
31880	SPI-HAYF	9.11	30	395	0.955	1	base	10hs2sa.sav
31558	DGLS CTY	60	30	303	0.975	1	base	10hs2sa.sav
31557	MILSTSTA	60	30	303	0.985	1	base	10hs2sa.sav
31556	TRINITY	60	30	303	0.987	1	base	10hs2sa.sav
31852	WEBR FL+	9.11	30	391	0.987	1	base	10hs2sa.sav
31559	MSS TAP1	60	30	303	0.986	1	base	10hs2sa.sav
31555	MSS TAP2	60	30	303	0.986	1	base	10hs2sa.sav
31562	LEWISTON	60	30	303	0.985	1	base	10hs2sa.sav
31553	BIG BAR	60	30	303	0.954	1	base	10hs2sa.sav
31564	FRNCHGLH	60	30	303	0.993	1	base	10hs2sa.sav
31095	HYAMPOM	60	30	303	0.927	1	base	10hs2sa.sav
31093	HYMPOMJT	60	30	303	0.928	1	base	10hs2sa.sav
31554	GROUSCRK	60	30	303	0.928	1	base	10hs2sa.sav
31850	CEDR FL+	9.11	30	391	0.928	1	base	10hs2sa.sav
31091	RDGE CBN	60	30	301	0.914	1	base	10hs2sa.sav
31098	HOOPA	60	30	301	0.851	1	base	10hs2sa.sav
31096	WILLWCRK	60	30	301	0.863	1	base	10hs2sa.sav
31566	KESWICK	60	30	303	1.01	1	base	10hs2sa.sav
31094	RUSS RCH	60	30	301	0.887	1	base	10hs2sa.sav
31092	MPLE CRK	60	30	301	0.894	1	base	10hs2sa.sav

Table 1a: Pre-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
31560	HAYFORK	60	30	303	0.779	1	tran_1	10hs2sa.sav	18%

31880	SPI-HAYF	9.11	30	395	0.779	1	tran_1	10hs2sa.sav	18%
31558	DGLS CTY	60	30	303	0.804	1	tran_1	10hs2sa.sav	18%
31557	MILSTSTA	60	30	303	0.816	1	tran_1	10hs2sa.sav	17%
31556	TRINITY	60	30	303	0.818	1	tran_1	10hs2sa.sav	17%
31852	WEBR FL+	9.11	30	391	0.818	1	tran_1	10hs2sa.sav	17%
31559	MSS TAP1	60	30	303	0.818	1	tran_1	10hs2sa.sav	17%
31555	MSS TAP2	60	30	303	0.818	1	tran_1	10hs2sa.sav	17%
31562	LEWISTON	60	30	303	0.843	1	tran_1	10hs2sa.sav	14%
31553	BIG BAR	60	30	303	0.826	1	tran_1	10hs2sa.sav	13%
31564	FRNCHGLH	60	30	303	0.884	1	tran_1	10hs2sa.sav	11%
31095	HYAMPOM	60	30	303	0.833	1	tran_1	10hs2sa.sav	10%
31093	HYMPOMJT	60	30	303	0.835	1	tran_1	10hs2sa.sav	10%
31554	GROUSCRK	60	30	303	0.835	1	tran_1	10hs2sa.sav	10%
31850	CEDR FL+	9.11	30	391	0.835	1	tran_1	10hs2sa.sav	10%
31091	RDGE CBN	60	30	301	0.839	1	tran_1	10hs2sa.sav	8%
31098	HOOPA	60	30	301	0.801	1	tran_1	10hs2sa.sav	6%
31096	WILLWCRK	60	30	301	0.813	1	tran_1	10hs2sa.sav	6%
31566	KESWICK	60	30	303	0.955	1	tran_1	10hs2sa.sav	5%
31094	RUSS RCH	60	30	301	0.839	1	tran_1	10hs2sa.sav	5%
31092	MPLE CRK	60	30	301	0.847	1	tran_1	10hs2sa.sav	5%

Table 1b: Pre-Project Trinity 115/60kV Transformer Contingency Results

Apply Solution

Installation of a ABB modular SVC rated at -40/+50MVAR at the Trinity 60kV substation would eliminate the low voltage concern. A SVC was placed on the TRINITY 60kV bus and Hayfork's pre-contingency voltage magnitude was recorded at 0.964p.u. The contingency caused no post transient voltage deviation leaving Hayfork's voltage magnitude at 0.964p.u. The output of the SVC post-contingency was recorded at +21.4MVAR. Tables 1c and 1d below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
31560	HAYFORK	60	30	303	0.964	1	base	10hs2sa_post_proj.sav
31880	SPI-HAYF	9.11	30	395	0.964	1	base	10hs2sa_post_proj.sav
31558	DGLS CTY	60	30	303	0.984	1	base	10hs2sa_post_proj.sav
31557	MILSTSTA	60	30	303	0.993	1	base	10hs2sa_post_proj.sav
31556	TRINITY	60	30	303	0.995	1	base	10hs2sa_post_proj.sav
31852	WEBR FL+	9.11	30	391	0.995	1	base	10hs2sa_post_proj.sav
31559	MSS TAP1	60	30	303	0.995	1	base	10hs2sa_post_proj.sav
31555	MSS TAP2	60	30	303	0.994	1	base	10hs2sa_post_proj.sav
31562	LEWISTON	60	30	303	0.992	1	base	10hs2sa_post_proj.sav
31553	BIG BAR	60	30	303	0.962	1	base	10hs2sa_post_proj.sav
31564	FRNCHGLH	60	30	303	0.998	1	base	10hs2sa_post_proj.sav

31095	HYAMPOM	60	30	303	0.935	1	base	10hs2sa_post_proj.sav
31093	HYMPOMJT	60	30	303	0.936	1	base	10hs2sa_post_proj.sav
31554	GROUSCRK	60	30	303	0.936	1	base	10hs2sa_post_proj.sav
31850	CEDR FL+	9.11	30	391	0.936	1	base	10hs2sa_post_proj.sav
31091	RDGE CBN	60	30	301	0.922	1	base	10hs2sa_post_proj.sav
31098	HOOPA	60	30	301	0.859	1	base	10hs2sa_post_proj.sav
31096	WILLWCRK	60	30	301	0.871	1	base	10hs2sa_post_proj.sav
31566	KESWICK	60	30	303	1.013	1	base	10hs2sa_post_proj.sav
31094	RUSS RCH	60	30	301	0.895	1	base	10hs2sa_post_proj.sav
31092	MPLE CRK	60	30	301	0.902	1	base	10hs2sa_post_proj.sav

Table 1c: Post-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
31560	HAYFORK	60	30	303	0.964	1	tran_1	10hs2sa_post_proj.sav	0.00%
31880	SPI-HAYF	9.11	30	395	0.964	1	tran_1	10hs2sa_post_proj.sav	0.00%
31558	DGLS CTY	60	30	303	0.984	100%	tran_1	10hs2sa_post_proj.sav	0.00%
31557	MILSTSTA	60	30	303	0.993	1	tran_1	10hs2sa_post_proj.sav	0.00%
31556	TRINITY	60	30	303	0.995	1	tran_1	10hs2sa_post_proj.sav	0.00%
31852	WEBR FL+	9.11	30	391	0.995	1	tran_1	10hs2sa_post_proj.sav	0.00%
31559	MSS TAP1	60	30	303	0.994	1	tran_1	10hs2sa_post_proj.sav	0.10%
31555	MSS TAP2	60	30	303	0.995	1	tran_1	10hs2sa_post_proj.sav	-0.10%
31562	LEWISTON	60	30	303	0.985	1	tran_1	10hs2sa_post_proj.sav	0.71%
31553	BIG BAR	60	30	303	0.975	1	tran_1	10hs2sa_post_proj.sav	-1.35%
31564	FRNCHGLH	60	30	303	0.989	1	tran_1	10hs2sa_post_proj.sav	0.90%
31095	HYAMPOM	60	30	303	0.955	1	tran_1	10hs2sa_post_proj.sav	-2.14%
31093	HYMPOMJT	60	30	303	0.956	1	tran_1	10hs2sa_post_proj.sav	-2.14%
31554	GROUSCRK	60	30	303	0.956	1	tran_1	10hs2sa_post_proj.sav	-2.14%
31850	CEDR FL+	9.11	30	391	0.956	1	tran_1	10hs2sa_post_proj.sav	-2.14%
31091	RDGE CBN	60	30	301	0.944	1	tran_1	10hs2sa_post_proj.sav	-2.39%
31098	HOOPA	60	30	301	0.885	1	tran_1	10hs2sa_post_proj.sav	-3.03%
31096	WILLWCRK	60	30	301	0.896	1	tran_1	10hs2sa_post_proj.sav	-2.87%
31566	KESWICK	60	30	303	1.008	1	tran_1	10hs2sa_post_proj.sav	0.49%
31094	RUSS RCH	60	30	301	0.919	1	tran_1	10hs2sa_post_proj.sav	-2.68%
31092	MPLE CRK	60	30	301	0.926	1	tran_1	10hs2sa_post_proj.sav	-2.66%

Table 1d: Post-Project Trinity 115/60kV Transformer Contingency Results

General Data

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the North Valley an outage of the Trinity 115/60kV transformer is projected to cause low voltages in the Trinity 60kV area.

PG&E lists that the mitigation plan is to transfer a portion of the 60kV loads to the Trinity-Maple Creek 60kV line if necessary. There is also mention of installing a UVLS; however there is no in-service date mentioned.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Trinity 60kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the low voltage issue described above.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete PG&E's long term plan.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution was in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

The network model used to perform this study was the WECC 2010 base case 10hs2sa.sav.

Please find the following technical data attached to this request:

- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
- Reliability and Maintainability Information (RAM_1JNR100004-713 REV 0.pdf)
- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF 17 SVCWSC Model.pdf & PSLF SVC model Parameter list.doc)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project

Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 495,000	$ 1,182,500	$ 1,089,000	$ 660,000	$ 3,426,500	$ 3,162,665
1	$ 10,505,000	$ 495,000	$ 1,129,288	$ 1,039,995	$ 630,300	$ 3,294,583	$ 3,162,665
2	$ 10,010,000	$ 495,000	$ 1,076,075	$ 990,990	$ 600,600	$ 3,162,665	$ 3,162,665
3	$ 9,515,000	$ 495,000	$ 1,022,863	$ 941,985	$ 570,900	$ 3,030,748	$ 3,162,665
4	$ 9,020,000	$ 495,000	$ 969,650	$ 892,980	$ 541,200	$ 2,898,830	$ 3,162,665
						$ 15,813,325	

Ratemaking Assumptions	TTS Costs
Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Cost of Capital	10.75%

The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 7.82% less than those of PG&E, as outlined below:

PG&E Cost

Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 495,000	$ 1,019,700	$ 1,969,000	$ 803,000	$ 4,286,700	$ 3,945,447
1	$ 10,505,000	$ 495,000	$ 973,814	$ 1,880,395	$ 766,865	$ 4,116,074	$ 3,945,447
2	$ 10,010,000	$ 495,000	$ 927,927	$ 1,791,790	$ 730,730	$ 3,945,447	$ 3,945,447
3	$ 9,515,000	$ 495,000	$ 882,041	$ 1,703,185	$ 694,595	$ 3,774,821	$ 3,945,447
4	$ 9,020,000	$ 495,000	$ 836,154	$ 1,614,580	$ 658,460	$ 3,604,194	$ 3,945,447
						$ 19,727,235	

Ratemaking Assumptions	PG&E Costs
Capital Cost	11,000,000
O&M (include Insurance)	17.9%
A&G	7.3%
Cost of Capital	9.27%

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

According to PG&E's service life analysis, this category of assets generally has a service life of 20 to 25 years with historical analysis showing that the average service life is slightly decreasing. Other electric utilities use service lives between 25 and 35 years for these types of assets at substations. PG&E proposes using an average service life of 25 years.

PG&E consistently uses negative rates for net salvage. While PG&E notes there is a trend of decreasing costs of removal, gross salvage is negligible and most retired equipment is not capable of being reused. For most retirements, the removal cost is much higher than the gross salvage receipt, resulting in negative net salvage. This is particularly the case where extensive labor is involved in removal or where California environmental laws require costly disposal. The range of estimates used in the electric industry is 5.00% to negative 20.00%. Therefore, PG&E proposes changing its current net salvage rate from negative 1.00% to negative 5.00%.

In contrast to the calculations used by PG&E, TTS is proposes using a service life of 20 years and a net salvage rate of 10.00% based on distinguishing characteristics of the facts which unlike those assets in the relevant PG&E account, involves a case of first impression not necessarily related to its historical data. The device is designed and intended to be both movable and easily removed. Because the device is movable, it is likely to have a slightly diminished service life of 20 years, in contrast to PG&E's assets with a service life of 25 years. Because the device is also designed to be easily removed with minimal labor, the main factor causing negative net salvage rates for PG&E's assets discussed above does not apply and therefore the net salvage rate is positive.

TTS will be using a 50/50 debt equity structure. The TTS cost of capital was derived by taking PG&E's published debt cost plus 2% plus return on equity (ROE) of 13.5%, then dividing by two. PG&E's debt cost was found in their current transmission owner rate case which was filed with the FERC. The following formula explains the method used to derive TTS cost of capital:

$$\frac{PTO\_DebtCost + 2\%}{2} + \frac{ReturnOnEquity}{2} = \frac{6\% + 2\%}{2} + \frac{13.5\%}{2} = 10.75\%$$

TTS's debt cost is based on taking the cost of capital of the PTO to which its equipment is connected, and adding 200 basis points. TTS is raising debt on a secured basis.

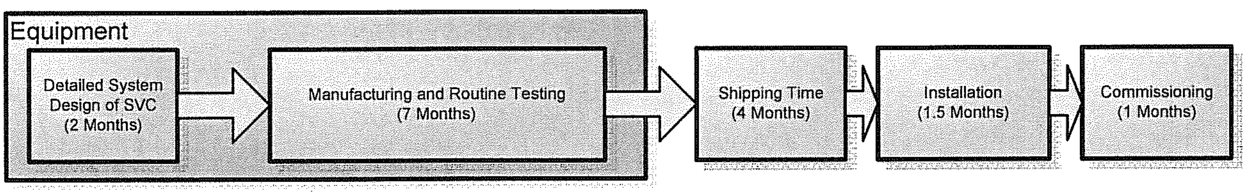
Therefore, TTS will pass through debt service payments from the service contract revenues, to a bank lockbox arrangement, and then to the lender. The credit risk the lender is assuming is, therefore, the credit risk of the PTO. To their debt cost TTS will add 200 basis points (we would be negotiating for a lower number), to account for the "liquidity premium" that a non-rated entity would pay over and above the PTO debt cost. The equity cost of capital is based on returns previously awarded merchant transmission projects in California; that is, the Trans-Bay Cable and Path 15.

Using the assumptions listed above, our analysis indicates that the TTS solution has a levelized annual revenue requirement of $3.2M compared to $3.9M for PG&E. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



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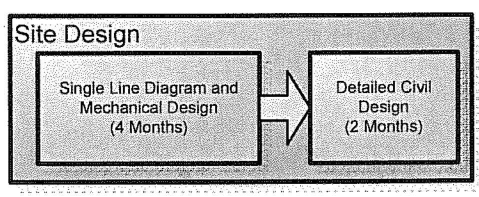


Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Watsonville Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **Watsonville 60kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the Central Coast and Los Padres areas an outage of the Green Valley-Watsonville 60kV line is projected to cause low voltages in the Watsonville, Granite Rock, and Brigatano 60kVsubstations. There is an existing Under Voltage Load Shedding (UVLS) scheme that will interrupt load at Watsonville when voltages dip below 0.92 p.u. By 2008 PG&E estimated that 13MW of load could be interrupted during peak conditions as a result of the UVLS. TTS studies indicated that this could rise as high as 15MW by 2010.

PG&E is proposing a long term solution to convert the 60kV system to 115kV by 2013. Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Watsonville 60kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the low voltage issue described above.

TTS feels that the Watsonville long term system conversion may not be complete by 2013 due to the lengthy approval process and equipment lead time. TTS is therefore requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete the system conversion. TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print):	**John Dizard**
Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

Technical Data

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

Planning Level Cost Data

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

    As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

Identify Concern

As outlined in the assessment results for the Central Coast and Los Padres areas an outage of the Green Valley-Watsonville 60kV line is projected to cause low voltages in the Watsonville, Granite Rock, and Brigatano 60kVsubstations. There is an existing Under Voltage Load Shedding (UVLS) scheme that will interrupt load at Watsonville when voltages dip below 0.92 p.u. By 2008 PG&E estimated that 13MW of load could be interrupted during peak conditions as a result of the UVLS. TTS studies indicated that this could rise as high as 15MW by 2010.

Validate Study Results

TTS confirmed the reliability concern by performing a load flow study using the WECC 2010 base case 10hs2sa.sav. Watsonville's pre-contingency voltage magnitude was recorded at 1.036p.u. The contingency caused a 22% post transient voltage deviation that left Watsonville's voltage magnitude at 0.81p.u. Tables 1a and 1b below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
36012	WTSNVLLE	60	30	319	1.036	1	base	10hs2sa.sav
36015	GRANT RK	60	30	319	0.996	1	base	10hs2sa.sav
36014	GRANT JT	60	30	319	1.003	1	base	10hs2sa.sav
36018	BRIGTANO	60	30	319	1.002	1	base	10hs2sa.sav
36022	LGNSTAP	60	30	319	1.001	1	base	10hs2sa.sav

Table 1a: Pre-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
36012	WTSNVLLE	60	30	319	0.81	1	line_1	10hs2sa.sav	22%
36015	GRANT RK	60	30	319	0.836	1	line_1	10hs2sa.sav	16%
36014	GRANT JT	60	30	319	0.844	1	line_1	10hs2sa.sav	16%
36018	BRIGTANO	60	30	319	0.846	1	line_1	10hs2sa.sav	16%
36022	LGNSTAP	60	30	319	0.934	1	line_1	10hs2sa.sav	7%

Table 1b: Pre-Project Green Valley-Watsonville 60kV Line Contingency Results

Apply Solution

Installation of an ABB modular SVC rated at -40/+50MVAR at Watsonville 60kV substation would eliminate the low voltage concern. A SVC was placed on the WTSNVLLE 60kV bus and the pre-contingency voltage magnitude was recorded at 1.036p.u. The contingency caused no post transient voltage deviation leaving Watsonville's voltage magnitude at 1.036p.u. The output of the SVC post-contingency was recorded at +31MVAR. Tables 1c and 1d below outline these results.

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
36012	WTSNVLLE	60	30	319	1.036	1	base	10hs2sa_post_proj.sav
36015	GRANT RK	60	30	319	0.996	1	base	10hs2sa_post_proj.sav
36014	GRANT JT	60	30	319	1.003	1	base	10hs2sa_post_proj.sav
36018	BRIGTANO	60	30	319	1.002	1	base	10hs2sa_post_proj.sav
36022	LGNSTAP	60	30	319	1.001	1	base	10hs2sa_post_proj.sav

Table 1c: Post-Project Base Case Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
36012	WTSNVLLE	60	30	319	1.036	1	line_1	10hs2sa_post_proj.sav	0.00%
36015	GRANT RK	60	30	319	0.988	1	line_1	10hs2sa_post_proj.sav	0.80%
36014	GRANT JT	60	30	319	0.995	1	line_1	10hs2sa_post_proj.sav	0.80%
36018	BRIGTANO	60	30	319	0.994	1	line_1	10hs2sa_post_proj.sav	0.80%
36022	LGNSTAP	60	30	319	0.997	1	line_1	10hs2sa_post_proj.sav	0.40%

Table 1d: Post-Project Green Valley-Watsonville 60kV Line Contingency Result

General Data

PG&E is proposing a long term solution to convert the 60kV system to 115kV by 2013. Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the Watsonville 60kV substation by October 2010. This interim solution is necessary for system reliability while PG&E implements their long term system conversion.

TTS feels that the Watsonville long term system conversion may not be complete by 2013 due to the lengthy approval process and equipment lead time. TTS is therefore requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required to complete the system conversion.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment themselves to meet reliability requirements rate payers would suffer large stranded costs in 2015 when the long term system conversion went into place.

Project Benefits:

- The Watsonville Interim Solution project will increase reliability to the customers in the Watsonville area that are affected by the UVLS.

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and 2 weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

The network model used to perform this study was the WECC 2010 base case 10hs2sa.sav.

Please find the following technical data attached to this request:

- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
- Reliability and Maintainability Information (RAM_1JNR100004-713 REV 0.pdf)
- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF SVC model Parameter list.doc & PSLF 17 SVCWSC Model.pdf)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project

Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 495,000	$ 1,182,500	$ 1,089,000	$ 660,000	$ 3,426,500	$ 3,162,665
1	$ 10,505,000	$ 495,000	$ 1,129,288	$ 1,039,995	$ 630,300	$ 3,294,583	$ 3,162,665
2	$ 10,010,000	$ 495,000	$ 1,076,075	$ 990,990	$ 600,600	$ 3,162,665	$ 3,162,665
3	$ 9,515,000	$ 495,000	$ 1,022,863	$ 941,985	$ 570,900	$ 3,030,748	$ 3,162,665
4	$ 9,020,000	$ 495,000	$ 969,650	$ 892,980	$ 541,200	$ 2,898,830	$ 3,162,665
						$ 15,813,325	

Ratemaking Assumptions	TTS Costs
Capital Cost	11,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Cost of Capital	10.75%

The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 7.82% less than those of PG&E, as outlined below:

PG&E Cost							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 11,000,000	$ 495,000	$ 1,019,700	$ 1,969,000	$ 803,000	$ 4,286,700	$ 3,945,447
1	$ 10,505,000	$ 495,000	$ 973,814	$ 1,880,395	$ 766,865	$ 4,116,074	$ 3,945,447
2	$ 10,010,000	$ 495,000	$ 927,927	$ 1,791,790	$ 730,730	$ 3,945,447	$ 3,945,447
3	$ 9,515,000	$ 495,000	$ 882,041	$ 1,703,185	$ 694,595	$ 3,774,821	$ 3,945,447
4	$ 9,020,000	$ 495,000	$ 836,154	$ 1,614,580	$ 658,460	$ 3,604,194	$ 3,945,447
						$ 19,727,235	

Ratemaking Assumptions	PG&E Costs
Capital Cost	11,000,000
O&M (include Insurance)	17.9%
A&G	7.3%
Cost of Capital	9.27%

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

According to PG&E's service life analysis, this category of assets generally has a service life of 20 to 25 years with historical analysis showing that the average service life is slightly decreasing. Other electric utilities use service lives between 25 and 35 years for these types of assets at substations. PG&E proposes using an average service life of 25 years.

PG&E consistently uses negative rates for net salvage. While PG&E notes there is a trend of decreasing costs of removal, gross salvage is negligible and most retired equipment is not capable of being reused. For most retirements, the removal cost is much higher than the gross salvage receipt, resulting in negative net salvage. This is particularly the case where extensive labor is involved in removal or where California environmental laws require costly disposal. The range of estimates used in the electric industry is 5.00% to negative 20.00%. Therefore, PG&E proposes changing its current net salvage rate from negative 1.00% to negative 5.00%.

In contrast to the calculations used by PG&E, TTS is proposes using a service life of 20 years and a net salvage rate of 10.00% based on distinguishing characteristics of the facts which unlike those assets in the relevant PG&E account, involves a case of first impression not necessarily related to its historical data. The device is designed and intended to be both movable and easily removed. Because the device is movable, it is likely to have a slightly diminished service life of 20 years, in contrast to PG&E's assets with a service life of 25 years. Because the device is also designed to be easily removed with minimal labor, the main factor causing negative net salvage rates for PG&E's assets discussed above does not apply and therefore the net salvage rate is positive.

TTS will be using a 50/50 debt equity structure. The TTS cost of capital was derived by taking PG&E's published debt cost plus 2% plus return on equity (ROE) of 13.5%, then dividing by two. PG&E's debt cost was found in their current transmission owner rate case which was filed with the FERC. The following formula explains the method used to derive TTS cost of capital:

$$\frac{PTO\_DebtCost + 2\%}{2} + \frac{\mathrm{Re}turnOnEquity}{2} = \frac{6\% + 2\%}{2} + \frac{13.5\%}{2} = 10.75\%$$

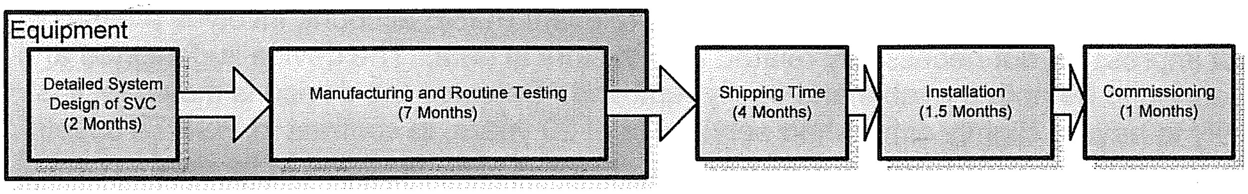
TTS's debt cost is based on taking the cost of capital of the PTO to which its equipment is connected, and adding 200 basis points. TTS is raising debt on a secured basis. Therefore, TTS will pass through debt service payments from the service contract revenues, to a bank lockbox arrangement, and then to the lender. The credit risk the lender is assuming is, therefore, the credit risk of the PTO. To their debt cost TTS will add 200 basis points (we would be negotiating for a lower number), to account for the "liquidity premium" that a non-rated entity would pay over and above the PTO debt cost. The equity cost of capital is based on returns previously awarded merchant transmission projects in California; that is, the Trans-Bay Cable and Path 15.

Using the assumptions listed above, our analysis indicates that the TTS solution has a levelized annual revenue requirement of $3.2M compared to $3.9M for PG&E. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



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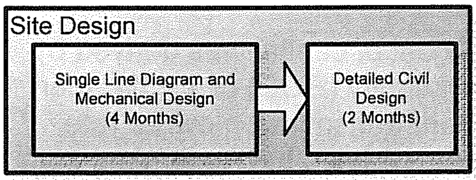

Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the appendix A (technical data) to the CAISO contact listed in section 4. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to provide additional information to be considered in the CAISO Transmission Plan. This submission is for (check one):

- ☐ Merchant Transmission Facility
- ☐ Economic Transmission Project from Participating Transmission Owner (PTO)
- ☐ Location Constrained Resource Interconnection Facility
- ☐ Demand Response Program
- ☐ Generation Project (under Economic Planning Study)
- ☐ Economic Planning Study Request
- ☒ Others

2. Please provide the following basic information of the submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **West Fresno Interim Solution**

Submission Date: **December 15, 2008**

b. Project location and the proposed interconnection point(s) **West Fresno 115kV Substation**

c. Project capacity (Net MW): **-40/+50 MVAR Capacity**

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project.

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the San Joaquin Valley an outage of the McCall-West Fresno 115kV line is projected to cause low voltages in the West Fresno 115kV bus.

PG&E is proposing a long term solution to install 75 MVARs of shunt capacitors at West Fresno or California Ave. 115kV Substation by May 2010.

Transmission Technology Solutions (TTS) is proposing an alternative solution that requires the installation of a direct connect -40/+50MVAR SVC at the West Fresno 115kV substation by October 2010. The preliminary power flow study results attached to this application show that the SVC will resolve the low voltage issue described above.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required from PG&E to complete a more long term plan. TTS feels that the CAISO should have enough time to evaluate this proposal and determine what is most economical for rate payers.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**10 / 15 / 2010**
Proposed Trial Operation date:	**10 / 15 / 2010**
Proposed Commercial Operation date:	**11 / 15 / 2010**
Proposed Term of Service:	**5 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

3. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Dukes
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

4. This Request is submitted by: **Transmission Technology Solutions, LLC**

Name of the Customer: **John Dizard**

By (signature): ______________________________

Name (type or print): **John Dizard**

Title:	**Managing Member & CEO**
Company Name:	**Transmission Technology Solutions, LLC**
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Date:	**12/15/2008**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[1]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route
- Evidence of securing the route or the ability to secure the route

Technical Data

- Network model for power flow study in GE-PSLF format
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data

Planning Level Cost Data

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[1] CAISO may request for more information later during the course of evaluation process

2. Generation Project Proposals

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the Generation Interconnection process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study in GE-PSLF or PSS/E format
- Geographical location, evidence of land procurement
- Dynamic models for stability study in GE-PSLF format
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation (please refer to data requirement for Wind Generator Interconnection Request from CAISO Generation Interconnection Process)
- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.
- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits.
- Other miscellaneous Data
- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3. Demand Responses and Other Proposals

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

4. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

5. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

  As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

Identify Concern

As outlined in the PG&E 2007 Electric Transmission Reliability Assessment Study Report for the San Joaquin Valley an outage of the McCall-West Fresno 115kV line is projected to cause low voltages in the West Fresno 115kV bus.

Validate Study Results

TTS confirmed the reliability concern by performing a load flow study using the WECC 2010 base case 10hs2sa.sav. The California Ave-West Fresno 115kV line loaded up to 100% of its highest applicable rating post contingency. The West Fresno 115kv bus had pre-contingency voltage magnitude of 0.953p.u.. The contingency caused a 11% post transient voltage deviation that left the West Fresno bus voltage magnitude at 0.85p.u. Tables 1a, 1b, and 1c below outline these results.

From	Name	kV	From	Name	kV	ck	MW	MVAr	MVA	Amps	pu_flow
34390	DANISHCM	115	34402	CAL AVE	115	1	-85.2	-24.2	88.6	514.3	1.004

Table 1a: Pre-Project McCall-West Fresno 115kV Contingency Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
34404	WST FRSO	115	30	314	0.953	1	base	10hs2sa.sav
34390	DANISHCM	115	30	344	0.951	1	base	10hs2sa.sav
34407	WFRES J2	115	30	314	0.951	1	base	10hs2sa.sav
34402	CAL AVE	115	30	314	0.951	1	base	10hs2sa.sav

Table 1b: Pre-Project Base Case Voltage Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
34404	WST FRSO	115	30	314	0.85	1	line_1	10hs2sa.sav	11%
34390	DANISHCM	115	30	344	0.864	1	line_1	10hs2sa.sav	9%
34407	WFRES J2	115	30	314	0.864	1	line_1	10hs2sa.sav	9%
34402	CAL AVE	115	30	314	0.865	1	line_1	10hs2sa.sav	9%

Table 1c: Pre-Project McCall-West Fresno 115kV Contingency Results

Apply Solution

Installation of a ABB modular SVC rated at -40/+50MVAR at West Fresno 115kV substation would eliminate the low voltage concern and postpone the overload of the California Ave-West Fresno 115kv line. A SVC was placed on the WST FRSO 115kV bus. The contingency caused no post transient voltage deviation at the West Fresno 115kV bus. In addition, the overload of the California Ave-West Fresno 115kV line was decreased to 0.89p.u. The output of the SVC post contingency was recorded at +34.9MVAR. Tables 1d, 1e, and 1f below outline these results.

From	Name	kV	From	Name	kV	ck	MW	MVAr	MVA	Amps	pu_flow
34390	DANISHCM	115	34402	CAL AVE	115	1	-85.1	11.8	85.9	455.8	0.89

Table 1d: Post-Project McCall-West Fresno 115kV Contingency Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name
34404	WST FRSO	115	30	314	0.953	1	base	10hs2sa.sav
34390	DANISHCM	115	30	344	0.951	1	base	10hs2sa.sav
34407	WFRES J2	115	30	314	0.951	1	base	10hs2sa.sav
34402	CAL AVE	115	30	314	0.951	1	base	10hs2sa.sav

Table 1c: Post-Project Base Case Voltage Results

Bus	Name	kV	Area	Zone	Vmag	Driver	Out_Name	Case_Name	Post Transient Voltage Deviation
34404	WST FRSO	115	30	314	0.953	1	line_1	10hs2sa.sav	0.00%
34390	DANISHCM	115	30	344	0.947	1	line_1	10hs2sa.sav	0.42%
34407	WFRES J2	115	30	314	0.946	1	line_1	10hs2sa.sav	0.53%
34402	CAL AVE	115	30	314	0.947	1	line_1	10hs2sa.sav	0.42%

Table 1d: Post-Project McCall-West Fresno 115kV Contingency Results

General Data

PG&E is proposing a long term solution to install 75 MVArs of shunt capacitors at West Fresno or California Ave. 115kV Substation by May 2010. Due to the lengthy approval process and long lead time, TTS feels that a installation date of May 2010 is unrealistic for PG&E to achieve.

Transmission Technology Solutions (TTS) is proposing an interim solution that requires the installation of a direct connect -40/+50MVAR SVC at the West Fresno 115kV substation by October 2010.

TTS is requesting a service contract of 5 years (2010-2015) with an option to extend the contract in 2015 if further time is required from PG&E to complete their long term plan.

Please find a white paper included in this application that outlines the CAISO's legal authority to implement this project itself, or to provide strong encouragement to PG&E to implement this project. (Legal and Policy Basis for Applicant's Proposed Solution)

TTS is offering PG&E a SVC equipment lease of 5 years to meet system reliability. The equipment leasing option has a large benefit to rate payers that PG&E cannot offer. If PG&E would have to purchase this equipment to meet reliability requirements, rate payers would suffer large stranded costs when the long term solution is in place.

Project Benefits:

- Increased dynamic and transient grid stability.
- Environmentally friendly solution that produces no waste or pollutants.
- Modularized design that makes installation quick and easy.
- Short construction period of only 15 months and two weeks from contract signing.
- Lowest cost to consumers.
- Avoids stranded cost.
- Avoids any high voltage problems that static capacitors can cause from remaining connected to the grid in off peak periods.
- Automatically adjusts to system conditions without operator intervention
- Does not require the excessive number of switching events that shunt capacitors need which can lead to voltage collapse

Please see the attached white paper that describes the benefits of using SVC's over static capacitors. (FACTS_SCAP_MIX.doc)

Technical Data

The network model used to perform this study was the WECC 2010 base case 10hs2sa.sav.

Please find the following technical data attached to this request:
- Single Line Diagram (01_Single_Line_Diagram.pdf)
- Plant Layout (02_Plant_Layout.pdf)
- Training Program (1. Training Program for Large SVC.pdf)
- Reliability and Maintainability Information (RAM_1JNR100004-713 REV 0.pdf)
- Sound Level Plot (Natural noise.pdf)
- GE PSLF Modeling data (PSLF SVC model Parameter list.doc & PSLF 17 SVCWSC Model.pdf)

Planning Level Cost Data

The project cost for the TTS 5 year lease option is outlined below:

Estimated Cost to CAISO Ratepayers for the CAISO Proposed Project							
Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 15,000,000	$ 675,000	$ 1,612,500	$ 1,485,000	$ 900,000	$ 4,672,500	$ 4,312,725
1	$ 14,325,000	$ 675,000	$ 1,539,938	$ 1,418,175	$ 859,500	$ 4,492,613	$ 4,312,725
2	$ 13,650,000	$ 675,000	$ 1,467,375	$ 1,351,350	$ 819,000	$ 4,312,725	$ 4,312,725
3	$ 12,975,000	$ 675,000	$ 1,394,813	$ 1,284,525	$ 778,500	$ 4,132,838	$ 4,312,725
4	$ 12,300,000	$ 675,000	$ 1,322,250	$ 1,217,700	$ 738,000	$ 3,952,950	$ 4,312,725
						$ 21,563,625	

Ratemaking Assumptions	TTS Costs
Capital Cost	15,000,000
O&M (include Insurance)	9.9%
A&G	6.0%
Cost of Capital	10.75%

The TTS project rates are highly competitive with PG&E rates. Overall TTS rates are 7.82% less than those of PG&E, as outlined below:

PG&E Cost

Year	Rate Base	Depreciation	ROE + Interest	O&M (include Insurance)	A&G	Revenue Req	Levelized Revenue Req
0	$ 15,000,000	$ 675,000	$ 1,390,500	$ 2,685,000	$ 1,095,000	$ 5,845,500	$ 5,380,155
1	$ 14,325,000	$ 675,000	$ 1,327,928	$ 2,564,175	$ 1,045,725	$ 5,612,828	$ 5,380,155
2	$ 13,650,000	$ 675,000	$ 1,265,355	$ 2,443,350	$ 996,450	$ 5,380,155	$ 5,380,155
3	$ 12,975,000	$ 675,000	$ 1,202,783	$ 2,322,525	$ 947,175	$ 5,147,483	$ 5,380,155
4	$ 12,300,000	$ 675,000	$ 1,140,210	$ 2,201,700	$ 897,900	$ 4,914,810	$ 5,380,155
						$ 26,900,775	

Ratemaking Assumptions	PG&E Costs
Capital Cost	15,000,000
O&M (include Insurance)	17.9%
A&G	7.3%
Cost of Capital	9.27%

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

According to PG&E's service life analysis, this category of assets generally has a service life of 20 to 25 years with historical analysis showing that the average service life is slightly decreasing. Other electric utilities use service lives between 25 and 35 years for these types of assets at substations. PG&E proposes using an average service life of 25 years.

PG&E consistently uses negative rates for net salvage. While PG&E notes there is a trend of decreasing costs of removal, gross salvage is negligible and most retired equipment is not capable of being reused. For most retirements, the removal cost is much higher than the gross salvage receipt, resulting in negative net salvage. This is particularly the case where extensive labor is involved in removal or where California environmental laws require costly disposal. The range of estimates used in the electric industry is 5.00% to negative 20.00%. Therefore, PG&E proposes changing its current net salvage rate from negative 1.00% to negative 5.00%.

In contrast to the calculations used by PG&E, TTS is proposes using a service life of 20 years and a net salvage rate of 10.00% based on distinguishing characteristics of the facts which unlike those assets in the relevant PG&E account, involves a case of first impression not necessarily related to its historical data. The device is designed and intended to be both movable and easily removed. Because the device is movable, it is likely to have a slightly diminished service life of 20 years, in contrast to PG&E's assets with a service life of 25 years. Because the device is also designed to be easily removed with minimal labor, the main factor causing negative net salvage rates for PG&E's assets discussed above does not apply and therefore the net salvage rate is positive.

TTS will be using a 50/50 debt equity structure. The TTS cost of capital was derived by taking PG&E's published debt cost plus 2% plus return on equity (ROE) of 13.5%, then dividing by two. PG&E's debt cost was found in their current transmission owner rate case which was filed with the FERC. The following formula explains the method used to derive TTS cost of capital:

$$\frac{PTO\_DebtCost + 2\%}{2} + \frac{ReturnOnEquity}{2} = \frac{6\% + 2\%}{2} + \frac{13.5\%}{2} = 10.75\%$$

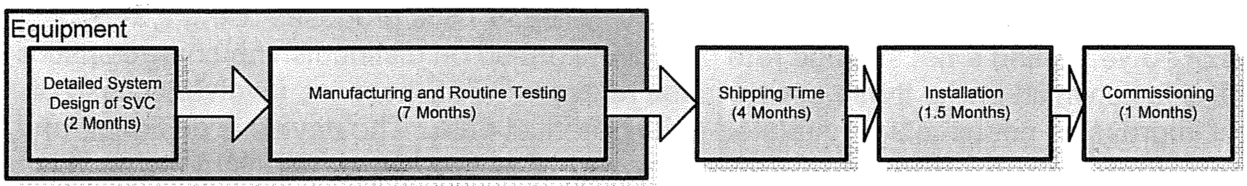
TTS's debt cost is based on taking the cost of capital of the PTO to which its equipment is connected, and adding 200 basis points. TTS is raising debt on a secured basis. Therefore, TTS will pass through debt service payments from the service contract revenues, to a bank lockbox arrangement, and then to the lender. The credit risk the lender is assuming is, therefore, the credit risk of the PTO. To their debt cost TTS will add 200 basis points (we would be negotiating for a lower number), to account for the "liquidity premium" that a non-rated entity would pay over and above the PTO debt cost. The equity cost of capital is based on returns previously awarded merchant transmission projects in California; that is, the Trans-Bay Cable and Path 15.

Using the assumptions listed above, our analysis indicates that the TTS solution has a levelized annual revenue requirement of $4.3M compared to $5.4M for PG&E. This preliminary analysis assumes the same number for years of service and capital cost. The savings in the TTS option is achieved by charging a lower O&M and A&G rates.

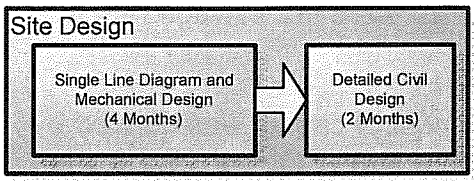
If the equipment is in place for the full depreciation period adopted by TTS, and the PTO wishes to acquire the equipment at that time, then TTS will enter into good faith negotiations to sell the equipment to the PTO for the residual value of the equipment.

Schedule

The estimated schedule is 15 months plus 2 weeks from contract signing. The chart below outlines a typical schedule.



During the 9 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Miscellaneous Data

Outline of responsibilities:

- Construct: TTS and ABB will construct the project under PG&E supervision.
- Own & Finance: TTS will both own and finance the project.
- Operate & Maintain: PG&E and ABB (under PG&E supervision).

ATTACHMENT B

Exhibit A

Legal and Policy Basis for Applicant's Proposed Solution

1. Outline of Proposed Solution

As summarized in the "Miscellaneous Data" section of the Applicant's RW Submission, Applicant has proposed a solution to the reliability problem presented at the XYZ, CA site (the "Site"). The FACTS-based solution Applicant proposes would substantially reduce the risk of load shedding which, in the absence of other measures, is the current "solution" for issues caused by voltage problems at the Site.

Designation of Applicant's solution by CAISO would be implemented by contractual arrangements with Applicant to deal with the identified reliability problem at the Site pursuant to which:

- Applicant and ABB will construct the proposed voltage support FACTS device (the "Device") at the Site, under PG&E supervision;
- Applicant will finance and own the Device;
- Pursuant to service contract arrangements, Applicant will provide voltage support to PG&E at the Site for a five-year term, subject to renewals by PG&E for two additional terms;
- Applicant will amortize the cost of the Device over its useful life and will assume the risk of non-renewal of the PG&E service agreement; and
- Operation and maintenance of the Device will be performed by PG&E with assistance from ABB.

By selecting Applicant's solution for the Site, PG&E's RW solution would be mooted. The PG&E proposal would entail direct and permanent ownership and operation of a Device at the Site, notwithstanding PG&E's announced intention to continue to build the new transmission lines which will relieve the need for provision of additional voltage support at the Site.

CAISO has the legal authority and policy basis to authorize and take all of the foregoing actions and applicable CAISO and FERC policies support the merits of its doing so.

2. Legal Authority of CAISO to Designate and Implement the Applicant's Proposal

The "CAISO Transmission Planning Process Request Window Procedures, Information, and Instructions," as revised on 11/14/08, is an important mechanism of CAISO for the implementation of FERC Order 890. The FERC Open Access Transmission Tariff promulgated under Order 890 applies specifically to "Reactive Supply and Voltage Control from Generation or Other Sources Service" (emphasis added). It is clear from the RW Submission Form that "other" persons besides PTOs may be treated as CAISO Stakeholder Customers eligible to make submissions to the Transmission Planning Process. Applicant's proposal and submission conforms in all respects to RW Submission Form Requirements. (While Applicant is not applying to become a jurisdictional entity of FERC, as discussed below, its proposed solution is consistent with and supports applicable FERC and CAISO policies.)

The procedure recommended for implementation of Applicant's proposed solution is in marked furtherance of key policies which FERC promulgated in Order No. 890, with which the CAISO RW process is designed to implement and foster. Order 890 articulates nine key planning principles to be reflected in processes like the RW, notably assurance of transparency and comparability. As pointed out in Summary to Order No. 890 (point 172 [p. 87]) FERC's policy motivations in promulgating these principles were notably to assure that lack of coordination, openness, and transparency not result in undue discrimination in transmission planning. In furtherance of these principles, CAISO can, among other things, compel utilities participating in the CAISO to pursue construction of transmission projects deemed needed to maintain system reliability (CAISO Tariff §2.4.1). CAISO's authority, not only to choose the optimum proposed solution but to direct the implementation by PG&E as the applicable PTO, is thus straightforward. It is equally applicable where implementation of a CAISO policy is determined by CAISO to be optimally made by a third party, *i.e.*, it is analogous to the implementation of the "competitive process for awarding projects to third parties developed with regulatory oversight" which the CAISO is implementing under its New Transmission Planning Process guidance (CAISO Policy Memo, dated 8/1/05). CAISO's intent is reflected further in CAISO's expression of "Core Values" of "Open Communication" articulated in its Annual Report (p. 19): [T]o seek out diverse ideas . . . promote "thoughtful leadership" and openly share information both internally and externally."

In sum, the FERC and CAISO procedures and policies with respect to the conduct of the RW process, the selection between PTO and other competing proposed solutions, and the implementation of those selected solutions not only are consistent with Applicant's submission, but suggest the policy merits of selecting Applicant's proposal.

3. Policy Considerations with Respect to Applicant's Proposal Solution.

Review of the facts surrounding the competing applications highlights several FERC and CAISO policy considerations which support Applicant's solution. Essentially, these facts are as follows:

Applicant supplied the CAISO transmission planning staff with its technical report in July, and Applicant has since further discussed its proposed solution with them. Applicant approached PG&E with its proposed solution in the expectation that it would be possible to make a joint proposal with PG&E to both CAISO and CPUC, since Applicant's solution represents a way to mitigate reliability problems requiring voltage support, during the time in which PG&E's long term solutions are planned and implemented. PG&E accepted the validity of Applicant's technical work. It is only recently that PG&E's lead engineer has informed Applicant has decided unilaterally to seek to install the Device on its own and include it as part of the rate base.

a. Support for Innovation. Applicant's proposal represents a linkage of a technical reliability enhancement Device to the optimum financing approach best suited to cost effective operation and overall system reliability. Applicant's approach to voltage support at the Site is an innovation; it meets reliability requirements while avoiding (as discussed below) the risk to ratepayers of incurring stranded costs. Applicant has been informed by PG&E that, in its competing RW application, it proposes to appropriate the technical solution developed by Applicant, but to link it to traditional utility financing techniques which are far less suitable for the purpose.

PG&E's alternative proposed RW solution lacks the innovative financial component of Applicant's submission, and is inconsistent with FERC and CAISO policies. Innovation is recognized by FERC in Order No. 890 as potentially improving transmission reliability through provision of active voltage support, provision of necessary transmission capacity for renewable resources, and encouragement of market entry of new service providers. Support for innovative approaches to financing of transmission is a specific area of positive commitment in CAISO's Annual Report this year (p. 24). In its decision-making, CAISO should take into account that, if PG&E's response to a good faith effort by Applicant to propose a timely solution to reliability problems is approved, the result will be to discourage other groups who would respond to CAISO's call for innovation.

b. Prudence and Avoidance of Stranded Costs. In addition, because the PG&E proposal would not present a least cost solution to the Site-specific problem, it might result in ratepayer charges for stranded costs and be subject to disallowance. As summarized above, Applicant's proposal to CAISO reflects a revenue model based on a limited term service contract. The intention is to earn a rate of return very close to that granted to existing merchant transmission projects in California, but without the risk to the ratepayers of stranded costs which could result if the requirement for the contracted voltage support at the site is alleviated by the longer term PG&E measures already approved by CAISO. As documented in the project economics portion of the "Miscellaneous Data" section of Applicant's RW submission, Applicant's substantially lower overhead costs more than offset the slightly higher cost of capital arising from the illiquidity premium on the pass-through of service contract payments by PG&E. As highlighted in the technical part of this submission, Applicant's lower overhead costs are made possible by Applicant's proposed modularization of the Device so it can be installed on a temporary basis and subsequently relocated to other system congestion sites.

In addition to this probable cost discrepancy, as compared to Applicant's proposal, PG&E's proposal also likely lead to costly transmission system overbuild. That will likely be the case because, in addition to installation of the Device and its inclusion as permanent parts of the PG&E rate base, PG&E plans to proceed with previously-planned long term transmission line projects which will ultimately render the shorter term Device solution redundant. Under FERC Order No. 679, with respect to "Prudently Incurred Costs to Meet Reliability Standards," recovery of all prudently incurred costs necessary to comply with mandatory reliability standards promulgated by an Electric Reliability Organization and approved by FERC under Federal Power Act Section 215 (Electric Reliability), FERC reviews applications for recovery of its prudently incurred costs under its Section 205 procedures. The converse of the foregoing recovery principle is true: costs incurred by PG&E in excess of those required for the purpose would not be viewed as incurred prudently and, therefore, would not be recoverable.

c. System Reliability Considerations. The cost redundancy and system overbuild intrinsic to the PG&E proposal for the Site would also have significant adverse reliability implications for PG&E's overall system as well. Installation of Devices as a permanent part of the rate base would reduce CAISO's ability to obtain more rapid solutions to reliability problems elsewhere on its system grid, as PG&E's planning, approval, manufacturing, and installation lead times would be considerably longer than Applicant's ability to remove and re-install Devices in less than four months. Under California Public Utilities Code §345, CAISO has been assigned the responsibility of ensuring the efficient use and reliable operation of the transmission grid. Flexibility will be important in the future, as active voltage support such as that supplied by the Devices is essential for renewables such as wind turbines. **Applicant's recent discussions with operators of the Irish and Danish grids, both heavy users of wind turbines, have established that additional active voltage support, such as that supplied by FACTS devices, has been found by those grid operators to be required not only at the connection points of wind turbines to the transmission grid (as is present U.S. practice), but at points closer to the load that uses the wind-generated power.** Applicant submits that the long and uncertain transmission expansion process currently underway, based principally on utility initiatives, will make it extremely difficult, if not impossible, to implement any state or Federal renewables initiatives on a timely basis in the absence of shorter lead-time approaches such as Applicant's. Applicant understands from manufacturers' representatives that it could implement its proposed solution implemented in time for the summer of 2011.

4. Conclusion.

Applicant's proposed RW solution is one which, in all respects, is consistent with CAISO and FERC legal authority and policy. It represents the type of innovation which aligns CASIO policy regarding provision of reactive power with the approach promulgated in FERC Order No. 890 and by CAISO. Applicant's proposed solution should be approved and implemented by CAISO in preference to that presented by PG&E.

ATTACHMENT C

- Renewable Resource Integration
- Other studies that required separate stakeholder processes such as Large Transmission projects

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

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

1.1.4 Transmission Plan BPM Requirements

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

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

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

1.2 Request Window Submissions

1.2.1 Description of Submissions

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

- Reliability-driven proposed upgrades or additions;
- Merchant facilities;
- Economic transmission projects based on economic efficiency and intended to mitigate ISO-identified congestion;
- Location constrained resource interconnection facilities;
- Projects to preserve long-term congestion revenue rights;
- Demand response programs;
- Generation projects submitted as proposed solutions along with economic study requests;
- Network upgrades identified through SGIP/LGIP; and
- Economic planning study requests

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

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

- One merchant transmission expansion project by a non-transmission owner;
- Two LCRIF projects submitted in the SCE service area proposed by SCE;
- Eleven projects submitted by non-transmission owners proposing equipment rental arrangements, with transmission owners, as mitigation solutions for reactive support deficiencies;
- A total of 103 PTO requests for reliability transmission upgrades and additions;
- One reliability project from a non-PTO
- One generation project submitted by a non-transmission owner as a reliability solution;
- Eight economic transmission projects; seven proposed by non-transmission owners and two proposed by a transmission owner.
- Five network upgrade projects identified by transmission owners through the LGIP/SGIP;
- Zero requests for economic studies; and
- One load interconnection project

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

1.2.2 Disposition of Request Window Submissions

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

1.2.3 Projects Eligible for Approval Recommendation in the 2009 Transmission Plan

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

Table 1-4 Economic Planning Study Requests (cont)

No	Name of Proposed Project	Description of Proposed Project	Project Category	Proposed On-Line Date
9	French Valley Energy Project	Install peakers on load side of Valley transformers. The project has 2 phases (49 MW/351 MW)	Reliability, install new generation in lieu of transmission alternative	Phase I 2010 Phase II 2013-2015
10	CDWR Study	N/A	Load interconnection.	2010
11	Mojave Interconnect	New facility between Kramer and Barstow	Merchant Transmission Facility	Jun-13

1.2.5 Ongoing Projects Not Eligible for Approval Recommendation in the 2009 Transmission Plan

This category of ongoing projects can be further divided into: a) Projects Requiring Further Information or Evaluation; and b) Conceptual Projects.

1.2.5.1 Projects Requiring Further Information or Evaluation

The following projects or proposals passed the initial ISO screening process but lacked the additional information necessary to gain recommendations for management or Board approval in this plan. These proposals will be studied during the 2009 study cycle in Stage 2 of the 2009 planning process.

Table 1-4 Ongoing Projects Requiring Further Information or Evaluation

No	Project	PTO Area	Project Evaluation Status
1	Cressey - Gallo 115 kV Line Project	PG&E	Reliability project under evaluation in 2009 study cycle
2	Embarcadero- Potrero 230 kV Transmission	PG&E	To be studied in the 2009 cycle along with alternatives
3	Ignacio-Mare Island 115 kV System Reinforcement Project	PG&E	Reliability project need to be integrated with a long-term study in this area which is still ongoing.
4	Kern - Old River 70 kV Line Reconductor Project	PG&E	Reliability project under evaluation in 2009 study cycle
5	Metcalf-Morgan Hill 115 kV Reinforcement Project	PG&E	Reliability project under evaluation in 2009 study cycle
6	Morro Bay-Midway 230 kV Line Nos 1. and 2 Reconductor	PG&E	LGIP network upgrade evaluated in 2009 study cycle
7	Mosher Transmission Project	PG&E	Reliability project under evaluation in 2009 study cycle

Table 1-3 Ongoing Projects Requiring Further Information or Evaluation (cont)

No	Project	PTO Area	Project Evaluation Status
8	San Luis Obispo Solar Switching Station #3	PG&E	LGIP network upgrade evaluated in 2009 study cycle
9	Santa Cruz 115 kV Reinforcement Project	PG&E	Reliability project under evaluation in 2009 study cycle
10	Watsonville 60 kV to 115 kV Conversion Project	PG&E	Reliability project under evaluation in 2009 study cycle; equipment leasing alternative being evaluated
11	West Fresno 115 kV Bus Upgrade Project	PG&E	Reliability project under evaluation in 2009 study cycle; equipment leasing alternative being evaluated
12	Wilson-Oro Loma 115 kV Reconductor Project	PG&E	Reliability project under evaluation in 2009 study cycle
13	West Fresno Interim Solution	PG&E	See line 11 above
14	Watsonville Interim Solution	PG&E	See line 10 above
15	Trinity Interim Solution	PG&E	Equipment leasing alternative under evaluation in 2009 study cycle; alternative also being evaluated
16	Shepard Interim Solution	PG&E	Equipment leasing alternative project under evaluation in 2009 study cycle
17	Old River Interim Solution	PG&E	See above
18	Maple Creek Interim Solution	PG&E	See above
19	Garberville Interim Solution	PG&E	See above
20	Camp Evers Interim Solution	PG&E	See above
21	Alberhill 500 kV Method of Service	SCE	Requires Board approval; alternatives being evaluated in 2009 study cycle
22	West of Devers 230 kV Lines Rebuild	SCE	Reliability project under evaluation in 2009 study cycle
23	Antelope - Bailey - Windhub System Reconfiguration	SCE	Reliability project under evaluation in 2009 study cycle
24	Eldorado - Ivanpah Transmission Project	SCE	LGIP network upgrade evaluated in 2009 study cycle
25	Cal Cemet Interim Solution	SCE	Equipment leasing alternative under evaluation in 2009 study cycle

Table 1-3 Ongoing Projects Requiring Further Information or Evaluation (cont)

No	Project	PTO Area	Project Evaluation Status
26	New Eastgate Tap 661 & 664	SDG&E	Reliability project under evaluation in 2009 study cycle
27	New ECO 500/230/69kV Substation & New 69kV Transmission Line to Boulevard Substation	SDG&E	LGIP network upgrade evaluated in 2009 study cycle
28	New 3rd 500/230 kV Transformer Bank (82) at Imperial Valley Substation	SDG&E	Economic project. Need further evaluation to confirm the need and benefits of the project
29	Orange County Transmission Expansion	SDG&E	Reliability project under evaluation in 2009 study cycle
30	Bayfront Transmission Substation	SDG&E	Reliability project under evaluation in 2009 study cycle
31	Barrett Interim Solution	SDG&E	Equipment leasing alternative under evaluation in 2009 study cycle
32	Table Mountain - Vaca Dixon 230 kV Reinforcement	PG&E	LGIP network upgrade evaluated in 2009 study cycle
33	Vaca Dixon - Sobrante - Moraga 230 kV Reinforcement	PG&E	LGIP network upgrade evaluated in 2009 study cycle

1.2.5.2 Conceptual Projects

Conceptual projects are proposals that have been submitted through the Request Window that are conceptual, or informational, and for which ISO approval recommendations have not been requested. These projects must be resubmitted through the Request Window when final plans of service are developed, or when specific needs have been identified.

Table 1-4 Conceptual projects

No	Project	PTO Area
1	Arco-Twisselman Area Reinforcement	PG&E
2	Ashlan- Gregg and Ashlan - Herndon 230 kV Reconductor	PG&E
3	Atlantic - Placer Voltage Conversion	PG&E
4	Atlantic - Rio Oso - Gold Hill 230 kV Lines	PG&E
5	Bay Area Bulk Transmission	PG&E
6	Borden Coppermine 70 kV Upgrade	PG&E
7	Brighton - Davis 115 kV Reconductoring	PG&E
8	Canada - Pacific Northwest - Norhtern CA Transmission Project	PG&E

ATTACHMENT D

AMENDMENT TO THE 2009 TRANSMISSION PLAN

The final version of the 2009 Transmission Plan was posted on March 20, 2009 and presented to the ISO Board of Governors on March 26, 2009. In Chapter 1, at Table 1-4, the ISO listed 33 projects submitted through the 2008 Request Window that required further information and accordingly could not be approved or rejected at the time the Plan was finalized.

Since the Plan was posted, the ISO was able to complete its evaluation of 13 projects listed as "pending" on Table 1-4. The disposition of these projects is set forth below. There will be no additional amendments to the Plan and the remaining proposals listed on Table 1-4 will be included in the 2010 Unified Assumptions and Study Plan.

I. Disposition of the Transmission Technology Solutions, Inc. Proposed Projects

In connection with the 2009 Transmission Plan, Transmission Technology Solutions, Inc. (TTS) has submitted eleven proposed reliability projects through the Request Window that involve deploying mobile Static VAR compensator (SVC) devices pursuant to service contracts with Participating Transmission Owners.[20] These projects responded to potential NERC reliability standard violations that the project proponent believed to exist, presently or in the future, at various locations on the PG&E, SCE and SDG&E systems. As part of its submission, TTS requests the ISO to direct the PTOs to enter into good faith negotiations to develop five year service contracts for these projects.

The TTS projects were described in the 2009 Transmission Plan as "interim solutions" and most of them were listed as ongoing projects requiring further information or evaluation in Table 1-4.[21] Given the short-term nature of these proposals, the ISO has completed its evaluation and is documenting its results in this amendment. A summary of the TTS proposals and the mitigation solutions recommended by the PTOs is set forth below.

Project Location	Violation Year	Project Name	Scope	Capability	Cost	Expected In-Service Date
Old River and Kern Area	2010 Studies showed a 135 % overload on some sections of Kern – Old River line and 0.95 pu at Old River for (L-1)	Old River Interim Solution (TTS)	Install -40/50 MVar SVC at Old River 70kV substation	Mitigates NERC category B undervoltage	15.8M	10-Oct
		Kern-Old River 70kV Reconductor (PGE)	Reconductor Kern – Old River Nos. 1 and 2 70kV Lines	Mitigates NERC category B overload and undervoltage	15M to 25M	11-May

[20] Static VAR compensators provide voltage support or reactive power compensation to transmission facilities.

[21] The ISO specifically denied the Cottonwood Interim Solution because there were no identified NERC reliability violations. See amended Transmission Plan, Table 7-4, page 222.

Project Location	Violation Year	Project Name	Scope	Capability	Cost	Expected In-Service Date
Santa Cruz Area	2010 Voltages in Rob Roy, Camp Evers area drop to 0.93 pu for (L-1/G-1)	Camp Evers Interim Solution (TTS)	Install -40/50 MVar SVC at Camp Ever 115kV substation	Mitigates NERC category B undervoltage	21.5M	10-Oct
		Santa Cruz 115kV Reinforcement (PGE)	- Rebuild Green Valley – Rob Roy 115kV Section into a Double circuit line - Install breakers at Rob Roy - Install 20-30 MVAR reactive support at Camp Evers	Mitigates NERC category B undervoltage	10M to 15M	11-Dec
Watsonville Area	2009 Voltage at Watsonville drops to 0.85 pu for L-1 (UVLS in place to drop load)	Watsonville Interim Solution (TTS)	Install -40/50 MVar SVC at Watsonville 60kV substation	Mitigates NERC category B undervoltage	15.8M	10-Oct
		Watsonville Voltage Conversion (PGE)	- Convert the Watsonville 60kV system to 115kV - New system will be connected into the Green Valley and Crazy Horse 115kV projects	Mitigates NERC category B undervoltage Mitigates NERC category C overload	25M to 30M	12-May
California and West Fresno Area	2009 Studies showed the Voltage at West Fresno Substation would drop to 0.88 pu for the loss of the McCall- West Fresno 115kV Line (L-1) 2018 Overload by 2% on California Ave-McCall 115kV Line for loss of the same line	West Fresno Interim Solution (TTS)	Install a direct connect -40/+50 MVAR SVC at West Fresno	Mitigates NERC category B undervoltage	16.3M	10-Oct
		Sanger - California 70kV to 115kV Voltage Conversion (PGE)	Reconductor and Convert the idle Sanger-California 70kV Line	Mitigates NERC category B overload and undervoltage	5M to 10M	11-May

Project Location	Violation Year	Project Name	Scope	Capability	Cost	Expected In-Service Date
Garberville Area	2009 Studies showed low voltages (approx 0.9 per unit) at Bridgeville, Fruitland, Fort Seward 60 kV substations following multiple contingencies (B and C)	Garberville Interim Solution (TTS)	Install a direct connect -40/+50 MVAR SVC at Maple Creek 60 kV substation	Mitigates NERC category B and C undervoltage	16.3M	Oct-10
		Garberville Reactive Support (PGE)	Install a 20 MVAR reactive support (SVC) at Maple Creek 60 kV substation	Mitigates NERC category B and C undervoltage	<10M	May-11
Maple Creek Area	2009 Studies showed low voltages (approx 0.88 per unit) at Ridge Cabin, Maple Creek, Russ Ranch, Willow Creek and Hoopa 60 kV substations following multiple contingencies (B and C)	Maple Creek Interim Solution (TTS)	Install a direct connect -40/+50 MVAR SVC at Maple Creek 60 kV substation	Mitigates NERC category B undervoltage	16.3M	Oct-10
		Maple Creek Reactive Support (PGE)	Install a 10 MVAR reactive support (SVC) at Maple Creek 60 kV substation	Mitigates NERC category B undervoltage	<5M	May-11
Trinity Area	2009 Voltage at Trinity 60 kV substation drops to 0.85 pu for L-1	Trinity Interim Solution (TTS)	Install a direct connect -40/+50 MVAR SVC at Trinity 60 kV substation	Mitigates NERC category B undervoltage	16.3M	Oct-10
San Diego Area	2010 Voltage deviation criteria violations in eastern San Diego 69 kV system for L-1	Barrett Interim Solution (TTS)	Install a direct connect -40/+50 MVAR SVC at Barrett 69 kV substation	Mitigates NERC category B voltage deviation and low voltage violations	16.3M	Oct-10

Project Location	Violation Year	Project Name	Scope	Capability	Cost	Expected In-Service Date
Antelope – Bailey Area (SCE Service Area)	2010 Potential voltage deviation more than 10% under N-1 for local 66 kV buses	Cal Cement Interim Solution Project (TTS)	Install a -40/+50 MVAR SVC at Cal Cement 66 kV substation	Mitigate low voltage dip under N-1 contingency condition for 66 kV buses in the Antelope – Bailey 66 kV system	$ 11 M	Oct-10

As discussed in further detail below, for most of the identified criteria violations, the PTOs have submitted long-term mitigation solutions to address these criteria violations. The ISO has completed its analysis of these long-term solutions and has determined that these projects can now move forward to implementation. However, the ISO also has determined that one or more of TTS proposed projects represent a cost effective alternative that would mitigate interim system reliability needs before the proposed long term solution would be implemented. With respect to the request that the ISO require PTOs to enter into good faith negotiations to deploy any of these proposed projects, the ISO does not believe its has explicit authority under Section 24.1 of its tariff necessary to require this outcome. Nonetheless, in some instances, the TTS proposed project presented the only mitigation solution proposed for ISO-identified near term reliability violations.

A. Projects Proposed for the PG&E Service Territory

1. Old River Interim Solution

The ISO identified Category B thermal overloads and under voltages in the Old River and Kern areas, starting in 2010. The TTS proposed solution can partially relieve the thermal overload in 2010 but will not be sufficient to mitigate under voltage conditions beyond 2010. PG&E's proposed solution, which involves recondutoring 35 miles of Kern-Old River lines 1 and 2, is a more cost-effective solution that will address both reliability violations. However, the PG&E solution will not be implemented until 2011.

2. Camp Evers Interim Solution

The ISO identified NERC Category B under voltages in the Santa Cruz (Rob Roy, Camp Evers) area starting in 2010. PG&E has proposed a more cost effective solution to address these violations by proposing to build a 115 kV DCTL line and installing MVAR support at Camp Evers on a permanent basis. This solution will not be implemented until 2011.

3. Watsonville Interim Solution

The ISO identified NERC Category B and C voltage drops, with a UVLS for Category C load drop, starting in 2009. The PG&E permanent solution, which will address both Category B and C violations, will not be implemented until 2012. The TTS proposal would provide an interim mitigation solution for the three year gap.

4. West Fresno Interim Solution

The ISO identified under voltages in the Fresno area, at the West Fresno substation, starting in 2009, with overloads identified on the California Ave-McCall line in 2018. PG&E has proposed a permanent solution that is more cost effective than the TTS proposal and will address both under voltage and thermal overloads. PG&E's permanent solution will be constructed in 2011. The TTS proposal would provide an interim mitigation solution for the one year gap.

5. Garberville Interim Solution

The ISO identified NERC Category B and C violations at several substations, following multiple contingencies, starting in 2009. The PG&E-proposed permanent solution, which is to install reactive support in Garberville in 2011, is more cost-effective than the TTS solution. The TTS proposal would provide an interim mitigation solution for the two year gap

6. Maple Creek Interim Solution

The ISO identified NERC Category B and C under voltage violations at several 60 kV substations in the Maple Creek area starting in 2009. PG&E proposed permanent solution, which is to install reactive support in the Maple Creek area in 2011, is more cost-effective than the TTS solution. The TTS proposal would provide an interim mitigation solution for the two year gap.

7. Trinity Interim Solution

The ISO identified NERC Category B under voltages at the Trinity 60 kV substation and its vicinity area starting in 2009. PG&E has not proposed a mitigation solution for this under voltage violation. While the ISO understands that PG&E has entered into discussions with the Trinity PUD to transfer Trinity PUD load out of PG&E service area to address this reliability violation, proposals from PG&E are required until the negotiations with Trinity PUD have concluded. The TTS proposal would provide an interim mitigation solution during the interim time period that an agreement with Trinity PUD is being formalized.

8. Shepard Interim Solution

The ISO has completed its analysis of the Shepard Interim Solution and has concluded that currently there is no reliability need for this proposal. A distribution-level substation that has been proposed by PG&E will include a shunt 50 MVAR capacity that will address load growth in the area.

B. Projects Proposed for the SCE Service Territory

Cal Cement Interim Solution

The ISO identified NERC Category B under voltage concerns at several 66 kV substations in the Antelope – Bailey 66 kV area in 2010 and beyond. SCE has proposed a permanent solution in which a new Antelope 230/66 kV transformer would be installed and the Antelope 66 kV transmission system would be split into radial systems to address multiple reliability concerns such as mitigating thermal overloads and contingency voltage dips for 66 kV buses in the area. SCE's proposed solution, still under development, was originally planned to be operational by the end of 2011 time frame and is a more comprehensive permanent solution when compared to TTS solution. The TTS proposal would provide an interim mitigation solution for the one year gap.

ATTACHMENT E

3.4.1.4 Post transient voltage stability analyses

Post transient voltage stability analyses were performed as part of the bulk system assessment for outages for which the power flow analyses indicated significant voltage drops. The two methodologies used were the post transient voltage deviation, and reactive power margin analyses.

3.4.1.5 Post transient voltage deviation analyses

Contingencies that showed significant voltage deviations in the power flow studies were selected for further analysis based on the WECC standards of 5% and 10% criteria for "N-1" and "N-2" contingencies respectively.

3.4.1.6 Transient stability analyses

Transient stability simulations were also performed as part of the bulk system assessment for critical contingencies to determine whether the system was stable and exhibited sufficient (positive) damping of system oscillations. This was done to ensure that the transient stability criteria for performance levels B and C as shown in table 3-1 were met.

Table 3-1: WECC transient stability criteria

Performance Level	Disturbance	Transient Voltage Dip Criteria	Minimum Transient Frequency
B	Generator One Circuit One Transformer PDCI	Max V Dip – 25% Max Duration of V Dip Exceeding 20% - 20 cycles Not to exceed 30% at non-load buses.	59.6 Hz for 6 cycles or more at a load bus.
C	Two Generators Two Circuits IPP DC	Max V Dip – 30% at any bus. Max Duration of V Dip Exceeding 20% - 40 cycles at load buses	59.0 Hz for 6 cycles or more at a load bus.

3.4.2 Study assumptions

3.4.3.1 Frequency of the study

Consistent with the ISO business practice manual (BPM) for transmission planning (TP), the ISO reliability assessment is performed once annually as part of its annual transmission planning process (TPP).

3.4.2.2 Study horizon

The NERC TPL 001, 002, and 003 standards and compliance related studies were performed for both the near term (i.e., year 2013) and long term (i.e., year 2018) scenarios. Additionally, the NERC TPL 004 standards relating to extreme system events were performed for the short-term (2013) scenarios only.

3.4.2.3 Study scenarios

The study scenarios cover critical system conditions driven by several factors. These factors are described below.

Peak Demands

Most of the ISO BAA experience summer peaking conditions. Hence, summer peak conditions were considered in all the various studies. In addition, for areas that experienced highest demand in the winter season, or where historical data indicated other conditions may require separate studies, winter peaks and summer off-peak studies were also performed. Examples of such areas are the Humboldt and

Table B-3: NERC TPL 003 Reference Table

Requirement	Control Activity	Note	Location
R1	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall		
R1.1	Be made annually	Reliability assessment which includes power flow and stability study is part of the annual ISO Transmission Planning Process. This activity is conducted annually through an open stakeholder process that starts in January of the first year and ends in March of the following year.	Section 1.3
R1.2	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons	The scope of ISO Transmission Planning Process covers both the operational and planning time frame. It includes technical study	BPM-Section 2.1.2 Section 1.3
R1.3	Be supported by a current or past study and/or system simulation testing that address each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	As stated in R1.1, the ISO conducts this assessment annually and the transmission plan is presented to ISO Board of Governors in February or March of each year. The scope of assessment covers evaluation of system conditions under normal (Category A) and emergency (Categories B, C, D) conditions	Chapter 4 (PG&E) Chapter 5 (SCE) Chapter 6 (SDG&E) Chapter 7 (All areas)

Table B-3: NERC TPL 003 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.3.1	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information	All category C contingencies were considered but only those category C contingencies that would produce more severe impact such as loss of two EHV transmission lines on the same corridor, loss of two nuclear units, and loss of double circuit tower lines, were evaluated	Section 3.4.2
R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity	The study models different system conditions e.g., load models, import MW flow that represent critical and stressed conditions in each area being studied.	Section 3.4
R1.3.3	Be conducted annually unless changes to system conditions do not warrant such analyses	As stated in R1.1, the ISO conducts this assessment annually	Section 1.3
R1.3.4	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions	The ISO studies were conducted on both 2013 and 2018 scenarios for normal, category B and category C outages. Category D contingencies were evaluated for selected long-term (2018) scenarios also. The PTOs also conduct similar studies covering the interim years.	Section 1.4 Section 3.4.2.2
R1.3.5	Have all projected firm transfers modeled	Path flows to/from each study area were modeled representing stressed conditions. This includes established firm transfers on selected paths. Future improvement on path capability also (if established) were modeled as well.	Section 3.4.2
R1.3.6	Be performed and evaluated for selected demand levels over the range of forecast system demands	Different demand levels were modeled in the study depending on the area being studied. In general, summer peak loads were studied in all areas since most areas under ISO footprints are summer peaking areas. However, winter and summer off-peak loads were also studied in several areas (e.g., winter peaking area) where these conditions were more severe.	Section 3.4.2

ATTACHMENT F

Table 3-2: Transmission Projects that were not recommend for approval by ISO staff

No	Project & Scope	Project Sponsor	CAISO Justications
1	Cottonwood Interim Solution	Transmission Technology Solutions LLC (TTS)	The CAISO could not find the need for this project. There is no low voltage probelm only a estimated voltage drop that can be solved through an operating solution. The generator(s) in the area should maintain a .98 pu voltage in the summer rather then 1.0
2	Missouri Flat Expansion	PG&E	The CAISO could not confirm the need for this project. Additional data was not supplied in the allowed time.
3	Rio Oso Reactive	PG&E	The CAISO could not confirm the need for this project. Additional data was not supplied in the allowed time.
4	Installation of additional capacitors on 230 and138 kV buses:	SDG&E	The CAISO studies did not show insufficient reactive margin for this outage. At this time, the project cannot be approved because SDG&E did not show the need.

ATTACHMENT G

Table 1-4 Economic Planning Study Requests (cont)

No	Name of Proposed Project	Description of Proposed Project	Project Category	Proposed On-Line Date
9	French Valley Energy Project	Install peakers on load side of Valley transformers. The project has 2 phases (49 MW/351 MW)	Reliability, install new generation in lieu of transmission alternative	Phase I 2010 Phase II 2013-2015
10	CDWR Study	N/A	Load interconnection.	2010
11	Mojave Interconnect	New facility between Kramer and Barstow	Merchant Transmission Facility	Jun-13

1.2.5 Ongoing Projects Not Eligible for Approval Recommendation in the 2009 Transmission Plan

This category of ongoing projects can be further divided into: a) Projects Requiring Further Information or Evaluation; and b) Conceptual Projects.

1.2.5.1 Projects Requiring Further Information or Evaluation

The following projects or proposals passed the initial ISO screening process but lacked the additional information necessary to gain recommendations for management or Board approval in this plan. These proposals will be studied during the 2009 study cycle in Stage 2 of the 2009 planning process.

Table 1-4 Ongoing Projects Requiring Further Information or Evaluation

No	Project	PTO Area	Project Evaluation Status
1	Cressey - Gallo 115 kV Line Project	PG&E	Reliability project under evaluation in 2009 study cycle
2	Embarcadero- Potrero 230 kV Transmission	PG&E	To be studied in the 2009 cycle along with alternatives
3	Ignacio-Mare Island 115 kV System Reinforcement Project	PG&E	Reliability project need to be integrated with a long-term study in this area which is still ongoing.
4	Kern - Old River 70 kV Line Reconductor Project	PG&E	Reliability project under evaluation in 2009 study cycle
5	Metcalf-Morgan Hill 115 kV Reinforcement Project	PG&E	Reliability project under evaluation in 2009 study cycle
6	Morro Bay-Midway 230 kV Line Nos 1. and 2 Reconductor	PG&E	LGIP network upgrade evaluated in 2009 study cycle
7	Mosher Transmission Project	PG&E	Reliability project under evaluation in 2009 study cycle

Table 1-3 Ongoing Projects Requiring Further Information or Evaluation (cont)

No	Project	PTO Area	Project Evaluation Status
8	San Luis Obispo Solar Switching Station #3	PG&E	LGIP network upgrade evaluated in 2009 study cycle
9	Santa Cruz 115 kV Reinforcement Project	PG&E	Reliability project under evaluation in 2009 study cycle
10	Watsonville 60 kV to 115 kV Conversion Project	PG&E	Reliability project under evaluation in 2009 study cycle; equipment leasing alternative being evaluated
11	West Fresno 115 kV Bus Upgrade Project	PG&E	Reliability project under evaluation in 2009 study cycle; equipment leasing alternative being evaluated
12	Wilson-Oro Loma 115 kV Reconductor Project	PG&E	Reliability project under evaluation in 2009 study cycle
13	West Fresno Interim Solution	PG&E	See line 11 above
14	Watsonville Interim Solution	PG&E	See line 10 above
15	Trinity Interim Solution	PG&E	Equipment leasing alternative under evaluation in 2009 study cycle; alternative also being evaluated
16	Shepard Interim Solution	PG&E	Equipment leasing alternative project under evaluation in 2009 study cycle
17	Old River Interim Solution	PG&E	See above
18	Maple Creek Interim Solution	PG&E	See above
19	Garberville Interim Solution	PG&E	See above
20	Camp Evers Interim Solution	PG&E	See above
21	Alberhill 500 kV Method of Service	SCE	Requires Board approval; alternatives being evaluated in 2009 study cycle
22	West of Devers 230 kV Lines Rebuild	SCE	Reliability project under evaluation in 2009 study cycle
23	Antelope - Bailey - Windhub System Reconfiguration	SCE	Reliability project under evaluation in 2009 study cycle
24	Eldorado - Ivanpah Transmission Project	SCE	LGIP network upgrade evaluated in 2009 study cycle
25	Cal Cemet Interim Solution	SCE	Equipment leasing alternative under evaluation in 2009 study cycle

Table 1-3 Ongoing Projects Requiring Further Information or Evaluation (cont)

No	Project	PTO Area	Project Evaluation Status
26	New Eastgate Tap 661 & 664	SDG&E	Reliability project under evaluation in 2009 study cycle
27	New ECO 500/230/69kV Substation & New 69kV Transmission Line to Boulevard Substation	SDG&E	LGIP network upgrade evaluated in 2009 study cycle
28	New 3rd 500/230 kV Transformer Bank (82) at Imperial Valley Substation	SDG&E	Economic project. Need further evaluation to confirm the need and benefits of the project
29	Orange County Transmission Expansion	SDG&E	Reliability project under evaluation in 2009 study cycle
30	Bayfront Transmission Substation	SDG&E	Reliability project under evaluation in 2009 study cycle
31	Barrett Interim Solution	SDG&E	Equipment leasing alternative under evaluation in 2009 study cycle
32	Table Mountain - Vaca Dixon 230 kV Reinforcement	PG&E	LGIP network upgrade evaluated in 2009 study cycle
33	Vaca Dixon - Sobrante - Moraga 230 kV Reinforcement	PG&E	LGIP network upgrade evaluated in 2009 study cycle

1.2.5.2 Conceptual Projects

Conceptual projects are proposals that have been submitted through the Request Window that are conceptual, or informational, and for which ISO approval recommendations have not been requested. These projects must be resubmitted through the Request Window when final plans of service are developed, or when specific needs have been identified.

Table 1-4 Conceptual projects

No	Project	PTO Area
1	Arco-Twisselman Area Reinforcement	PG&E
2	Ashlan- Gregg and Ashlan - Herndon 230 kV Reconductor	PG&E
3	Atlantic - Placer Voltage Conversion	PG&E
4	Atlantic - Rio Oso - Gold Hill 230 kV Lines	PG&E
5	Bay Area Bulk Transmission	PG&E
6	Borden Coppermine 70 kV Upgrade	PG&E
7	Brighton - Davis 115 kV Reconductoring	PG&E
8	Canada - Pacific Northwest - Norhtern CA Transmission Project	PG&E

ATTACHMENT H

Appendix C: Stakeholder comments and the ISO responses

The table below summarizes stakeholder comments the ISO received during the 2008 planning cycle

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
In response to Draft 2009 CAISO Transmission Study Plan ("Plan") (ISO's 1st Transmission Plan stakeholder meeting).	Mark A. Frazee Anaheim Public Utilities Department Date Submitted: 3/20/2008	In presentations at the March 10, 2008 stakeholder meeting, SCE did not expressly identify either objective as part of its planning process. The CAISO should require that reduction in LCR and RMR should be one of the primary objectives in transmission planning.	The ISO agrees with this comment and will consider this in future studies.
	Erin K. Moore Southern California Edison Date Submitted: 3/24/2008	Assumption for Mohave Plant The Mohave Plant does not intend to operate during the years 2013 through 2018. Therefore, SCE recommends the CAISO to revise its generation assumption to reflect the Mohave Plant as non-operational between the years of 2013 to 2018.	Based on the information the ISO received from SCE, the Mohave plant was considered available to meet the load and was modeled online n 2018 scenarios only.
	Erin K. Moore Southern California Edison Date Submitted: 3/24/2008	Transmission Planning Process (TPP) Integration between TPP with its newly proposed generation interconnection process.	This is an ongoing process and the ISO will inform the stakeholders regarding this activity once the updates are available.
In response to the ISO presenting study results and alternatives. (ISO's 2nd Transmission Plan stakeholder meeting)	Susan R. Schneider Phoenix Consulting Date Submitted: 11/22/08	Observations: There appear to be inconsistencies between the ISO and PTO study results (i.e., recommended transmission projects) for the same areas. However, it is difficult to even determine the nature, extent, or reasons for the apparent inconsistencies	The ISO appreciates this input and tried to address these concerns by hosting two follow-up conference calls on December 3, 2008 and on January 16, 2009 to address these issues. The ISO staff also contacted stakeholders directly to answer their detailed engineering questions.

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
In response to the ISO presenting study results and alternatives. (ISO's 2nd Transmission Plan stakeholder meeting)	Barry Flynn Date Submitted: 11/19/2008	It would be very helpful if you could describe in detail any changes the CAISO made to the base cases made available earlier to state holders on a restricted basis from the CAISO website. It would also be helpful if changes are made to the existing system for the 5 year case, those needed to be summarized. We also need to know any changes that are made between the 5 year case and the 10 year case. There are many references to various SPS schemes throughout the CAISO studies. We need to know the details of the worst contingencies to meaningfully participate in the expansion plan process. The same comment applies to knowing the assumed elements removed from the system for bus faults. We would like CAISO to provide the details for all the "worst contingencies".	The ISO appreciates this input and will internally discuss options to help ensure better documentation in future studies. The ISO believes that several efforts were made by its staff to answer these questions during this planning cycle to try to help clarify these questions. The ISO Transmission Plan should also provide more information and clarification.
In response to the ISO presenting study results and alternatives. (ISO's 2nd Transmission Plan stakeholder meeting)	Gary Chen Southern California Edison	From a technical perspective, overall SCE does not have issues with the CAISO study results; However, SCE does have a clarifying question about an assumption. SCE requests that the CAISO clarify how it modeled the proposed CPV units. An additional Stakeholder Meeting in Southern California is Needed Updated Transmission Planning Base Cases Need to be Posted	The ISO recommends this comment to be discussed during the drafting of the 2010 Study Plan. This will allow the technical study to be conducted accordingly. The ISO realized that stakeholder access to its process across the ISO controlled Grid is important. During 2009, opportunities to enhance stakeholder participation will be considered, and if appropriate, implemented. Once the updated transmission planning base cases are available, they will be posted on the ISO secured website
In response to the ISO presenting study results and alternatives. (ISO's 2nd Transmission Plan stakeholder meeting)	Marco Rios Pacific Gas & Electric Date Submitted: 12/17/2008	PG&E recognizes that the CAISO has addressed PG&E's long-standing concerns regarding the lack of a defined process for obtaining approval by the CAISO Board of Governors for transmission projects with capital costs in excess of $50 million. The CAISO has mentioned that it will detail its recommendation and action items for projects	The ISO has considered these comments, discussed with PG&E, and consider these comments in the final Transmission Plan

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
		requiring CAISO Board approval in the CAISO Transmission Plan, which will be finalized in the first quarter of 2009. In addition, PG&E also provided detailed comments on Study Results by each PG&E Area	
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Ann T. Finley Metropolitan Water District of Southern California Submitted: 3/9/2009	Did CAISO perform any independent analysis of the Devers 230/115 KV area? The overloads and voltage violations listed in SCE's Expansion Plan were not identified in the CAISO Transmission Plan report, nor was the BEP SPS validated in the ISO report.	The ISO performed the study for the Devers 230 kV system area. However, the Devers 115 kV was not included in the ISO study since it is not part of the ISO controlled grid.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Karen Shea Southern California Edison Submitted: 3/13/2009	I. Transmission Projects Overview SCE requests confirmation from the CAISO that SCE's proposed Alberhill Substation is included in the list of projects being submitted to the CAISO Board for approval in May or June 2009. As part of the 2009 Transmission Plan Draft, the CAISO has included publicly-available transmission project information in the form of two lists: Notably absent is a list of major transmission projects (those costing more than $50 million) which the CAISO anticipates being recommended for approval by the CAISO Board in 2009. Complicating matters is the fact that the CAISO staff has chosen to treat transmission projects being proposed by third-party and merchant transmission developers as confidential. Such treatment by the CAISO seems contradictory to the requirements of FERC's Order 890	The ISO included the Alberhill Substation project under the category of ongoing that once all supporting information and the ISO management has concurred with this project, it can be presented to the ISO board of governors for approval. Please refer to chapter 1 and chapter 7 of the ISO Transmission Plan report. The ISO intends to provide this information during the 1st 2010 ISO Transmission Plan stakeholder meeting that will be held in March 2009. In addition, the ISO will try to include the requested information in the Transmission Plan report.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan	Karen Shea Southern California Edison	II. Projects Submitted in the Request Window Must be Made Available to the PTO SCE recommends that the CAISO make all	

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
	Submitted: 3/13/2009	transmission project proposals available to all interested stakeholders on an across-the-board basis (subject to CIS requirements). Otherwise, the planning process will not be moving in a direction of openness and transparency. Rather, the process will become far more controversial and subject to question.	As shown above, the ISO will provide a list of the Study Requests that came through the2008 Request Window in the 2009 ISO Transmission Plan.
(3rd stakeholder meeting) In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Karen Shea Southern California Edison Submitted: 3/13/2009	III. Detailed Comments on CAISO 2009 CAISO Transmission Plan Draft 1. Study Conditions The CAISO Transmission Plan report should consider and reference SCE's assessments and reports to cover the complete breadth of critical loading conditions for NERC/WECC compliance purposes. 2. Alberhill Substation Given that SCE has provided the necessary information to the CAISO, the project should be included as a "Project Requiring CAISO Board Approval" in the Final Report. SCE requests confirmation from the CAISO that SCE's Alberhill Substation is on a list of projects requiring CAISO Board approval and that the CAISO intends to approve the project no later than May or June 2009. 3. West of Devers SCE notes that a new generator proposed to connect at Devers Substation was not modeled in the CAISO's study. Therefore, the CAISO's study does not follow the protocol of generation assumptions for new power plants in the study plan. Nonetheless, additional information is needed in the draft report to outline the degree of thermal overloads in the area, exact timing and scope of transmission system upgrades	1. Study Conditions The ISO studied the most critical conditions of peak load to determine required transmission infrastructure needed to serve load. The off-peak load conditions, while also critical, present scenarios where generation can be re-dispatched to serve load. It, therefore, represents an economic dispatch scenario where the ISO has options to select the most efficient generating units needed to serve load. For the upcoming planning cycle, the ISO will evaluate both summer peak load and off-peak load conditions. Incidentally, according to the WECC/NERC, studies of different load conditions other than peak load fall under Guidelines (not Standards) of WECC-G3 (Identification of Critical Conditions). Guidelines are what WECC and NERC encourage planning entities to consider and follow, but are not considered requirements. The ISO does plan to consider and follow WECC/NERC Guidelines. 2. Alberhill Substation The CAISO Staff noted that further supporting data are needed for the Alberhill Substation Project. These are listed in the following: Project alternatives Itemized cost and details of proposed transmission upgrades

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
		necessary and what (if any) impact the CPV Sentinel project may have on the corridor if the project becomes operational. 4. Appendix on SVC Study (for Tehachapi) Additional information is needed in the CAISO's draft report to outline the induction motor load modeling assumptions for the Tehachapi and SCE system. 5. Timing Concerns of Reliability Projects SCE's Transmission Planning group is concerned about CAISO approval of projects that cost less than $50 million and have a short lead/development time. In the event these projects may be delayed or miss the planned Operating Date, the CAISO project will be delayed until the following year's Request Window. The project review may also be delayed by the CAISO due to insufficient data. 6. Diligence Needed in Utilizing Maps SCE requests the CAISO be diligent in utilizing maps in information that is publicly available. Anything that is potentially sensitive from a CIS or other perspective should be provided to qualified stakeholders and diligence taken to represent an appropriate level in broad public documents. 7. Additional Concerns SCE is also concerned that Pages 208-209 in the 2009 CAISO Transmission Plan Draft posted and dated February 2009 still contain the description and diagram of Vincent-Mesa 500kV. The line is no longer in the TRTP Plan of Service and should be removed.	Comparison with a competing generation project alternative. The ISO Staff will be working with SCE Staff in reviewing the above required information. 3. West of Devers The CAISO does follow ISO Planning Standards accurately in modeling the new generation projects in the studies. The new generation project as mentioned by SCE still does not have the permit approval from the California Energy Commission. The ISO Planning Standards specifically requires new generation projects receive the CEC permit to construct before being included in the long-term planning studies. 4. Appendix on SVC Study (for Tehachapi) After the ISO Draft Report was posted, the ISO Staff has provided SCE Staff with relevant power flow study cases and dynamic data for ISO evaluation of dynamic and static reactive requirements associated with the Tehachapi Transmission Project. 5. Timing issue The ISO appreciates this comment and is looking forward to work with SCE and stakeholders in the future to address this concern. 6. Diligence Needed in Utilizing Maps The ISO will work with SCE for an approved format of drawings needed for illustration and presentation purposes in the future. 7. Additional Concerns The ISO concurs with this comment and will modify the report per SCE's request

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
		IV. Stakeholder Meetings/Issues 1. SCE suggested that the CAISO continue to hold at least one stakeholder meeting in each of the PTO service territories to ensure that the public has an opportunity to participate in this important process. 2. PTO Transmission Expansion Plan and Third Party/Merchant Project Information As part of the CAISO Annual Transmission Expansion Planning process the PTOs provide the CAISO with their Transmission Expansion Plan. Also, as described in Section II of these comments, the CAISO tariff and BPM requires the CAISO, in coordination with the stakeholders, review information received and validated during the Open Season. SCE understands from the development of the FERC O 890 process and tariff that the CAISO would be setting up a secure part of its website to post this information for qualified users. This is a critical and an important part of a meaningful O 890 stakeholder process and SCE requests that the CAISO follow through on developing such a website and process.	The ISO concurs with these comments and will work with SCE on this issue in this planning cycle
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting) In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Susan Schneider CalWEA Submitted: 3/13/2009	CalWEA comments and questions LCRIF development & assessment process: We understand that the ISO planning process was somewhat chaotic this cycle, due to (among other things) Order 890 compliance workload on ISO staff. However, we hope that the ISO will: Give affected generators (and others that may pay part of the LCRIF cost) an opportunity to examine the ISO analyses of these and future LCRIF proposals it receives; and Make a statement of its support for involvement of affected generators in development of future LCRIF	LCRIF development & assessment process: The ISO concurs with these comments Request for abbreviated stakeholder process: The Order 890 stakeholder process is sufficient to address this need. The ISO is willing to discuss ~~specific concerns that CALWEA has related to the proposed LCRIF projects. Please initiate this~~ communication by emailing regionaltransmission@caiso.com.

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
		proposals in its final recommendations for the LCRIF Projects. Request for abbreviated stakeholder process: We ask ISO to conduct a short stakeholder process before the May Board meeting that would, at a minimum: Share the information submitted to the ISO in the LCRIF Project proposals, Clarify which generation projects the LCRIF Projects are intended to serve; Clarify the on-line dates for the LCRIF Projects Share the ISO analyses leading to its positive recommendation on the LCRIF Projects.	
	Jenny Mueller Transmission Technology Solutions Submitted: 3/13/2009	TTS Comments on CAISO Stakeholder meeting Feb 27th: 1. For projects that cost less than $50M and do not require CAISO board approval, is there any reason the CAISO management cannot approve the project prior to 2010? 2. We want to make sure our projects will be considered as an interim solution. 3. In the meeting there was some indication that the CAISO compared PG&E equipment costs (only) to TTS costs that included capital cost, O&M, A&G, ROE and Interest. Was a more detailed cost breakdown provided from PG&E?	Currently, approval of the project $50M or less is done in accordance with the BPM. Also, the ISO appreciates the clarifications from TTS and will request for more information if it is needed. The ISO appreciates these comments and is looking forward to working with TTS and other stakeholders to resolve this issue.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Steve Greenleaf J.P. Morgan Ventures Energy Corporation Submitted:	The Need to Discuss Certain Policy Issues Upon review, while the applicable CAISO Tariff and BPM provisions establish certain information requirements for such proposals and provide guidelines regarding the priority at which these proposal's will be reviewed, the provisions do not	Clarification will be added to the Transmission Planning Process BPM during 2009.

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
	3/13/2009	detail how the CAISO will evaluate proposed transmission projects against non-transmission alternatives. Moreover, the provisions do not detail the contractual and other provisions necessary to support integration of non-transmission projects, or non-traditional transmission project proposals, into the CAISO system. J.P. Morgan understands that these are difficult issues. However, J.P. Morgan also understands that the CAISO received proposals from both non-transmission project sponsors and non-traditional transmission project sponsors during the most recent request Window. While none of these proposals appeared to be accepted in the CAISO's 2009 Transmission Plan Report, the question as to how to evaluate these proposals against traditional transmission projects appears ripe. J.P. Morgan recommends that these issues be discussed in the full light of day and that the CAISO initiate a stakeholder process on these issues	
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Steve Greenleaf J.P. Morgan Ventures Energy Corporation Submitted: 3/13/2009	The Need to Discuss Certain Policy Issues Upon review, while the applicable CAISO Tariff and BPM provisions establish certain information requirements for such proposals and provide guidelines regarding the priority at which these proposal's will be reviewed, the provisions do not detail how the CAISO will evaluate proposed transmission projects against non-transmission alternatives. Moreover, the provisions do not detail the contractual and other provisions necessary to support integration of non-transmission projects, or non-traditional transmission project proposals, into the CAISO system. J.P. Morgan understands that these are difficult issues. However, J.P. Morgan also understands that	Clarification will be added to the Transmission Planning Process BPM during 2009.

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
		the CAISO received proposals from both non-transmission project sponsors and non-traditional transmission project sponsors during the most recent request Window. While none of these proposals appeared to be accepted in the CAISO's 2009 Transmission Plan Report, the question as to how to evaluate these proposals against traditional transmission projects appears ripe. J.P. Morgan recommends that these issues be discussed in the full light of day and that the CAISO initiate a stakeholder process on these issues	
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Steve Greenleaf J.P. Morgan Ventures Energy Corporation Submitted: 3/13/2009	Process Refinements J.P. Morgan recommends that the CAISO consider certain process-related refinements to its new transmission planning process. J.P. Morgan applauds the CAISO for attempting to incorporate into its process the various venues that may give rise to needed new transmission projects or proposed alternatives, be it the general transmission planning process, the Large Generator Interconnection Process (LGIP), the Long-Term Congestion Revenue Rights (LT-CRR) process, or the Local Capacity Requirements study process(LCR) (see generally BPM for Transmission Planning process at p.21). J.P. Morgan recommends that the CAISO consider refinements to the process to more explicitly acknowledge in all of the aforementioned processes projects proposed and discussed in one particular venue that may impact another. For example, transmission projects proposed in the transmission planning process for the purpose of addressing NERC/WECC/CAISO reliability criteria should be explicitly identified and considered in a timely manner in the CAISO's LCR Study process.	The ISO concurs with this comment. A key objective of our process is that the ISO's planning process will provide a comprehensive view of all parallel studies and its impacts on one another.
In response to ISO presenting projects	Theresa Mueller & Barry Flynn	Local Capacity Requirements	Please see similar questions raised by J.P Morgan and City of Anaheim. In addition, this question may

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	City of County of San Francisco (CCSF) Submitted: 3/13/2009	Section 8 of the Draft Report includes a reference to the ISO Local Capacity Requirements (LCR) Studies. However, no real effort is taken to evaluate the economics of transmission in reducing the LCR. This is a major deficiency with the existing report.	be addressed through the LCR study as well.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Theresa Mueller & Barry Flynn City of County of San Francisco (CCSF) Submitted: 3/13/2009	Generation Level Assumed for CAISO Grid Expansion Studies Based upon the draft report wording, it appears both the Potrero Gas Turbines and the SF Peakers (& SFO Peaker) are assumed to be operational simultaneously in the ISO's power flow studies. A listing of actual generation online for the 2013 and 2018 assessment studies would allow stakeholders to evaluate the reasonableness of the CAISO generation assumptions. Even without that, it is readily apparent that too much generation was assumed for both years in the assessment studies. In closing, CCSF appreciates the opportunity to comment on the CAISO 2009 Grid Expansion Plan and requests CAISO cooperation in ensuring that all of Potrero Generation can be retired next year.	The ISO appreciates this comment and will incorporate it in the 2010 Transmission Plan. Also, the ISO encourages the CCSF to continue participating in the ISO planning process.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Barry Flynn & Pushkar Wagle Bay Area Municipal Transmission group (BAMx) Submitted: 3/13/2009	Load Dropping for Category C/Category D Contingencies BAMx urges the ISO to be consistent in applying the Planning Standards (http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf) to determine the need for a given transmission project. Historically, for Category C and D contingencies, no justification has been offered for new project additions or SPSs. However the TransBay Cable, a $450 million project, is an example of a recent project that addresses a Category C	The ISO concurs and will address this comment as part of the 2010 Transmission Plan.

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
		contingency. We request the CAISO to clearly state conditions under which transmission projects would be appropriate for Category C violations and justify these projects accordingly. It is imperative for the CAISO to follow the existing planning standards or create new, but consistently applied, standards across different areas.	
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Barry Flynn & Pushkar Wagle Bay Area Municipal Transmission group (BAMx) Submitted: 3/13/2009	Power Flow Contingency Analysis Was the loss of two transformers analyzed as a Category C contingency for all or any of the PTO areas? Were there any "combinations of any one element outage followed by double-circuit tower line outages" conducted? If so, what were they? Please describe.	A loss of two transformers is considered as C contingency according to the NERC/WECC standards. The combinations of any one element outage followed by double-circuit tower line outages" were conducted under LCR study
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Barry Flynn & Pushkar Wagle Bay Area Municipal Transmission group (BAMx) Submitted: 3/13/2009	Post Transient Voltage Stability Analyses Section 3.4.1.4 of the Draft Report discusses the Post transient voltage stability analyses. Were such analyses or any reactive power margin analyses conducted for the Greater Bay Area? Please clarify.	The LCR study conducted this study based on WECC criteria (please see the criteria in the 2009 TPP for more information).
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Barry Flynn & Pushkar Wagle Bay Area Municipal Transmission group (BAMx) Submitted: 3/13/2009	List of Contingencies Page 12 of the Draft report indicates that the list of contingencies is available on the ISO secured website for the contingencies. We have accessed an Excel file comprising about 74 contingencies in Northern California. However, this does not appear to be the complete list. If this list is not the one mentioned above, please identify its location.	The complete list of the contingencies was uploaded on the Regional Transmission secure webpage. Please contact the ISO staff if you have question regarding the location of these files.

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Barry Flynn & Pushkar Wagle Bay Area Municipal Transmission group (BAMx) Submitted: 3/13/2009	List of Transmission Projects Table 7-2 (Section 7.1) shows the Transmission Projects that were not recommend for approval by ISO staff. Please provide some indication of why they were not approved and/or the requirements for project approval. Section 7.3 lists the ongoing projects. Please distinguish between the projects that "are being developed by project sponsors" and those projects that "the ISO has conceptually agreed with the scope of the projects yet still require further evaluation or additional information". Which, if any of these projects, would be considered for approval in the 2009 planning cycle?	The final report will provide more information that addresses these issues.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Barry Flynn & Pushkar Wagle Bay Area Municipal Transmission group (BAMx) Submitted: 3/13/2009	Local Capacity Requirements Section 8 of the Draft Report includes the reference to the ISO Local Capacity Requirements (LCR) Studies. However, no real emphasis is placed on evaluating the economics of the transmission in reducing the LCR. It appears, especially for GBA, where the reactive margin sets the level of LCR needs, that additional reactive capability may be economically justified to reduce the LCR requirements.	Please see similar questions raised by J.P Morgan and City of Anaheim
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Barry Flynn & Pushkar Wagle Bay Area Municipal Transmission group (BAMx) Submitted: 3/13/2009	Various detailed technical questions regarding the ISO study (see detailed comment at http://caiso.com/1ca5/1ca5d8334b920.html)	The ISO appreciates these comprehensive comments and will work with this entity to resolve these issues. In addition, for the question regarding the assumptions in the ISO study results in the greater bay area, the ISO will re-evaluate its technical study and provide the updates in the transmission report if any of these assumptions impacts the ISO study results.
In response to ISO presenting projects	Brian Murphy	Thank you for considering SDG&E's initial comments before the draft posting. Attached are SDG&E's	

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	San Diego Gas & Electric Submitted: 3/13/2009	official follow-up comments based on the draft plan posted 3/6/09. p. 191 Orange County Transmission Upgrade Project: The name of this project has been changed to "Capistrano-Talega Reliability Upgrade". Please include this name as a replacement or subtitle wherever the project is mentioned. p. 206: South Bay Relocation Project/Bayfront: SDG&E has submitted this project as an Aging Infrastructure project and as such, in agreement with discussion between SDG&E and the CAISO, the project should be not be subject to ISO Board approval. p. 206: ECO Substation: This project was submitted as a Reliability and LCRI project. This project should be listed in Table 3-4, indicating the need for ISO Board Approval. p. 208: Talega-San Mateo: Approval of TL13835 Tap project on p. 201 mitigates this problem. p. 208: Upgrade Miguel 69kV to Breaker and a Half: SDG&E does not believe the risk of bus outage justifies the high cost to completely change the breaker configuration. As a Category C bus outage, loss of load is allowed. However, we are investigating adding individual circuit breakers to minimize the effect of a bus outage. p. 208: Escondido 230 kV Breaker: There are space limitations currently at Escondido. Adding breakers to these two transformers would require major modifications to the 230 kV switchyard. p. 208: Add a third source to big load centers >100 MW: SDG&E has investigated adding third circuits to Mesa Rim and Granite Hills. SDG&E does not feel that mitigation projects are justified at this time, but is	

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
		aware that load dropping is allowable for these scenarios, and will continue to evaluate these substations through the Grid Assessment process. For the Margarita and Laguna Niguel Substations, the submitted Capistrano-Talega Reliability Upgrade/Orange County Expansion Plan will improve reliability in the area. p.226: The operational/target date for the Sunrise Powerlink is June 2012, although SDG&E and CAISO studies assumed the 2011 date for this expansion plan.	
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Mark Esguerra Pacific Gas & Electric Submitted: 3/13/2009	Individual CAISO Project Approval Letters---In addition to the posting of the CAISO's Transmission Plan document, PG&E requests that the CAISO provide individual letters of approval for each of the project proposals once approved by the CAISO Management or the CAISO Board.	Management will determine an appropriate communication to address this concern.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Mark Esguerra Pacific Gas & Electric Submitted: 3/13/2009	CAISO Board Approval Process---When a proposed transmission project requires CAISO Board approval, such as those listed on Table 7-3, PG&E requests that the CAISO Staff provide a list of clear milestones that need to be met by both the PTO and the CAISO.	The ISO concurs with this comment and will address this comment as part of the 2010 Transmission Plan.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Mark Esguerra Pacific Gas & Electric Submitted: 3/13/2009	Processing of Competitive Projects----There were three PG&E transmission proposals that were previously identified as "recommended for approval" by CAISO Staff in the draft Transmission Plan posted on February 13, 2009, but later changed to a status of "Active" in the March 6 revision. The "Active" status for these proposals indicates that these projects will not be approved in the 2009 Transmission Plan. The CAISO Staff stated that these changes are due to a reevaluation of third-party competing proposals specifically in the Kern, Central Coast and Los Padres areas.	The ISO is obligated to evaluate all project proposals, including competitive alternatives, to ensure that the most beneficial project for ISO customer is selected. The ISO will complete its analysis and provide its recommendation in 2009.

Topic Area	Submitter (name and company)	Comment Submitted	ISO Response
		PG&E urges the CAISO to make a decision now regarding the approval of the three PG&E project proposals before the 2009 Transmission Plan is finalized. Without the CAISO approval in 2009, PG&E cannot complete these projects in time to be compliant under certain outage conditions.	
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Mark Esguerra Pacific Gas & Electric Submitted: 3/13/2009	Comprehensive comments on specific projects and studies (see detailed comment at http://caiso.com/1ca5/1ca5d8334b920.html)	In general, the ISO agrees with these comments and will consider them in future studies. In addition, for the question regarding the assumptions in the ISO study results in the greater bay area, the ISO will re-evaluate its technical study and provide the updates in the transmission report if any of these assumptions impacts the ISO study results.
In response to ISO presenting projects and draft 2009 ISO Transmission Plan (3rd stakeholder meeting)	Mark Esguerra Pacific Gas & Electric Submitted: 3/13/2009	Specific Comments on the 2009 Transmission Plan Document PG&E requests that a copy of the Executive Summary, Chapter 1 and Chapter 2 be made available to stakeholders with an opportunity to comment on those sections. The current Transmission Plan that was provided does not have those sections included.	The draft final Transmission Plan will contain these chapters and PG&E is welcome to provide any comments to the ISO before the board meeting date.

C. Projects Proposed for the SDG&E Service Territory

1 Barrett Interim Solution

The ISO identified NERC Category B under voltage and reactive margin concerns in the 69 kV system in eastern San Diego County in 2010 and beyond, and proposed several alternative mitigation solutions. The Barrett Interim Solution proposed by TTS will not address all of the violations identified for 2010 and the ISO determined that it will create additional overloads. Thus, the TTS proposal is not a feasible mitigation solution and other mitigation plan must be considered.

II. Disposition of Other Projects

A. PG&E's Wilson Oro Loma 115 kV Reconductor Project

This project was identified in Table 1-4 of the 2009 ISO transmission plan and it consists of network upgrades developed in the Large Generator Interconnection Process (LGIP) for generation in the ISO's serial study group. As such, this project can go forward in the LGIP process without further study in the 2010 Transmission Planning Process.

B. SCE's Alberhill 500 kV Method of Service

Based on additional information provided by SCE following their submission of the Alberhill 500 kV project through the Request Window, the ISO believes it will be able to present the project to ISO Management, and if approved, to the ISO Board of Governors at their September 2009 meeting. The ability of the ISO to meet this schedule is based on the availability of the necessary data required to perform the analysis.

C. SDG&E Bayfront Transmission Substation

Based on additional information provided by SDG&E following their submission of the Bayfront Transmission Substation project through the Request Window, the ISO believes it will be able to present the project to ISO Management, and if approved, to the ISO Board of Governors at the September 2009 meeting. The ability of the ISO to meet this schedule is based on the availability of the necessary data required to perform the analysis.

ATTACHMENT I

TTS Comments on CAISO Stakeholder meeting Feb 27th:

1. Projects that cost less than $50M only require executive management approval. In the stakeholder meeting it was described that projects costing less than $50M and are listed as "On-going" will not be approved for the 2009 study year. The soonest that an on-going project that cost less than $50M will be approved is 2010. For projects that cost less than $50M and do not require CAISO board approval, is there any reason the CAISO management cannot approve the project prior to 2010?
2. Various long term reliability projects received approval. Our projects were proposed as an interim solution until a long term project is in place; meaning that the approved long term PG&E project will not be in place before violating system reliability constraints. We want to make sure our projects will be considered as an interim solution.
3. In the meeting there was some indication that the CAISO compared PG&E equipment costs (only) to TTS costs that included capital cost, O&M, A&G, ROE and Interest. Was a more detailed cost breakdown provided from PG&E?

Jenny Mueller

ATTACHMENT J

Pacific Gas and Electric Company

Introduction

PG&E appreciates the opportunity to provide comments in response to the 2010 CAISO Transmission Plan, Draft Study Plan posted on March 17, 2009. The CAISO held the 2010 CAISO Transmission Plan Stakeholder Meeting on March 24, 2009. Below are PG&E comments that address: 1) 2008 Request Window Project Status Changes, 2) the Once-Through Cooling (OTC) Study, 3) Evaluation of Study Requests, 4) the Unified Planning Assumptions, 5) Large Generator Interconnection Process (LGIP) Coordination, 6) Greater Bay Area Long Term Study, and 7) specific comments on the 2010 Transmission Plan Document.

Comments

1. **2008 Request Window Project Status Changes**---During the March 24 Stakeholder Meeting, the CAISO staff stated that unapproved projects submitted in the 2008 Request Window may be approved if there is sufficient information and the planning studies can be completed within the 2009 study cycle. The CAISO also mentioned that an amended Transmission Plan may reflect several changes and will be completed within the next few months. The delay could have an impact on three PG&E transmission reliability project proposals in the Kern, Central Coast and Los Padres areas that were initially identified as "recommended for approval" by CAISO Staff in the draft Transmission Plan posted on February 13, 2009, and later changed to a status of " On-going " in the March 6 revision. The CAISO staff previously stated that these changes were due to a reevaluation of third-party competing proposals. PG&E notes that it has provided all of the required information for all three projects to be deemed "valid" as well as subsequent information that would help the CAISO Staff to make a decision.

   PG&E urges the CAISO to make a decision now regarding the approval of the three PG&E project proposals. With the CAISO approval in 2009, PG&E can complete these projects in time, and as a result both PG&E and the CAISO would be in compliant with North American Electric Reliability Corporation (NERC) standards under certain outage conditions.

   In addition, PG&E also urges the CAISO to provide to stakeholders a clearly defined process regarding the evaluation of competitive projects. PG&E does not understand the CAISO's reluctance in sharing the proposals submitted by third party companies. The current CAISO process allows third party companies to view and comment on PTO proposals submitted in the Request Window, PG&E believes that, per FERC Order No. 890 and the CAISO's Business Planning Manual (BPM), PTOs should also be allowed the same opportunities.

2. **Once-Through Cooling (OTC) Study**---The Once-Through Cooling (OTC) study effort was not specifically discussed at the Stakeholder Meeting. However, Mr. Gary DeShazo did mention that the CAISO is currently working with the State Water Quality Control Board, California Energy Commission, and California Public Utilities Commission (CPUC) on this issue. Other than these brief remarks, no details were provided on the on-going inter-agency effort or whether stakeholders would be afforded the opportunity to comment. PG&E urges the CAISO to involve PTOs in the study process.

   At the meeting, Mr. DeShazo also stated that the OTC study will not be included as part of the 2010 Transmission Plan, but that it will be evaluated as a stand-alone study. As the study of the removal of OTC units is imperative to understanding future transmission and generation requirements, PG&E requests that the CAISO coordinates and performs the OTC study as an integral part of the 2010 Transmission Plan. The study results should identify the alternatives available to replace OTC units, considering transmission, demand-side, and supply alternatives. PG&E has included a proposed analytical framework for the CAISO's consideration in Appendix A.

3. **Evaluation of Study Requests**--- During the March 24 Stakeholder Meeting, the CAISO staff mentioned that 11 Study Requests, including seven economic projects, were received from the 2008 Request Window. The economic projects will be considered as part of the Economic Planning Study as potential solutions to identified congestion needs. PG&E requests that the CAISO include projects in the base case that have achieved a Phase 2 status from the Western Electricity Coordinating Council (WECC). These projects, in addition to approved projects, should be placed in the base cases before other proposed economic projects are studied.

   This practice is consistent with the requirements in the WECC "Overview of Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports" as to when a project must be considered when studying new projects.

   > P.34, Section 3.2.5: Phase 2 Requirements states: "All projects with Planned Ratings should consider each other as appropriate in their planning studies. Once a project has entered Phase 2 it has attained a Planned Rating and is considered on an equal basis with other projects similarly situated in Phase 2. Projects in Phase 2 are not ranked according to degree of disagreement regarding specific project issues. The term "similarly situated" refers to the relative timing of projects based on the stage of study that each project is in within Phase 2. For example, if a Phase 2 project has substantially completed studies, it would be further ahead in the process compared to a project that has just begun its studies. These projects would not be "similarly situated."
   >
   > P.37, Section 3.4: Monitoring Project Progress states: "Granting of Phase 2 status or an Accepted Rating to a project/project sponsor obligates other WECC members to various levels of recognition and accommodation in the planning of other projects."

   Therefore, the Canada-Pacific Northwest-Northern California (CNC) Transmission Project which has achieved Phase 2 status should be included in the study assumptions for the economic projects studies. In addition, consistent with open and transparent transmission planning, PG&E requests to be an active participant in the Economic Planning Study.

4. **Unified Planning Assumptions - Demand Forecast (Section 1.1.8)**---The CAISO primarily relies on CEC IEPR load forecasts as the primary source to estimate future electricity demand. The CEC provides 10-year IEPR forecasts every other year. The current 10-year forecast was published in 2007. The CEC will be publishing the latest draft 10-year forecast in either April or mid-May, with the final CEC IEPR forecast to be published in August 2009.

   The CEC IEPR load forecast is primarily driven by population projections and does not necessarily considers the current state of the economy. Due to the current state of the economy within the PG&E service area, PG&E's demand forecast is lower for the first few years, beyond which the PG&E forecast will be similar to the 2007 CEC IEPR forecast for the PG&E northern California region.

   During the recent Stakeholder Meeting, PG&E requested CAISO staff to consider incorporating any load disparities in CAISO's planning studies if there is a significant difference in the forthcoming CEC draft forecast as compared to the 2007 CEC forecast. The CAISO staff agreed that any significant load disparities should be considered and requested

PG&E assistance regarding the local area load distribution in PG&E service territory. PG&E agrees to provide any necessary assistance regarding the load forecasts if there is a significant difference.

5. **Large Generator Interconnection Process (LGIP) Coordination (Section 1.6)**--- The CAISO staff discussed the consideration of LGIP Network Upgrades that were submitted into the 2008 Request Window during the Stakeholder Meeting. The CAISO staff mentioned that the technical analyses to identify Network Upgrades required to access generation in the Transition Cluster may be included in the 2010 Unified Assumptions and Study Plan. There was no mention during the Stakeholder Meeting if these analyses would actually be included.

   The CAISO mentioned that the approval of network upgrades associated with generation interconnections that were submitted into the 2008 Request Window will be contingent upon: 1) consistency with the outcome of the CAISO's Phase I Interconnection Studies for the Transition Cluster, 2) the project must be an efficient means by which to interconnect generation, and 3) the project must be supported by sufficient generation that has posted the necessary Interconnection Financial Security.

   It is still unclear as to how the CAISO plans to treat transmission projects originating from the LGIP. Will these projects need to be submitted in the Request Window? Will projects over $50 million need approval from the BOG? In a reversal from the 2009 Transmission Plan stakeholder meeting on February 27, 2009, the CAISO stated that network upgrades identified from the GIPR process will need to be submitted into the 2009 request window, but network upgrades would still receive CAISO approval as part of the GIPR process.

   PG&E submitted two such network upgrade projects into the 2008 Request Window: the San Luis Obispo Solar Switching Station #3 and the Morro Bay-Midway 230 kV Line Nos. 1 and 2 Reconductor Projects. These two projects are needed for the interconnection of solar power generation in the Carrizo Plains area. Specifically, PG&E has signed Purchase Power Agreements (PPAs) with OptiSolar and SunPower for 850 MWs in the Carrizo Plains area. Both PPAs have received CPUC approval. PG&E requests clarification with respect to the approval process of network upgrades so that these renewable resources can be expeditiously interconnected.

6. **Greater Bay Area Long Term Study**---As part of an effort spanning the last few planning cycles, the CAISO has conducted a Greater Bay Area Long Term Study Stakeholder process. As part of this study effort, a Phase 1 study report had been drafted. PG&E requests further clarity on the future of this study including a proposed timeline and finalization of the Phase 1 report.

7. **Specific Comments on the 2010 Transmission Study Plan Document**

   - ***Peak Demands*---**Section 1.1.5, page 6: Historically, PG&E is a summer-peaking system. However, there are pockets within PG&E service territory that can experience higher demand during non-summer months. Examples of these areas are Central Coast, North Coast and parts of the Greater Bay Area. To address this issue, PG&E will develop and analyze additional seasonal cases, specifically winter coastal cases, to assess system performance for these conditions.

   - ***Contingencies***---Section 1.1.5, page 8: The segment discussing Category D contingencies states "... only the following category D contingencies ... will be included in the study." There are no specific contingencies listed.

- ***Generation Assumptions---*** Section 1.1.6 lists the new generation projects that will be modeled in the CAISO base cases. This list is based on the information from the CEC website; it does not include several wind generation projects in PG&E territory, specifically the Shiloh Wind Farm II (Shiloh II), Western GeoPower Unit 1, and Hatchet Ridge Wind Farm projects. Please add these generation facilities to "New generation projects that will be included in the ISO near-term Reliability Assessment" (Table 2 on page 8).

  In addition, PG&E requests that the Mariposa Energy Project also be included in the generation study assumptions as PG&E recently filed an application (A09-04-001) at the CPUC requesting approval of a PPA with Mariposa.

  http://docs.cpuc.ca.gov/efile/A/99291.pdf

- ***Firm Transfer***---Section 1.1.11, page 14: PG&E's winter coastal base cases will model Path 26 at 2800 MW (N-S) and Path 66 at 3800 MW (N-S) as it was modeled in previous PG&E winter base cases.

- ***Protection System---***Section 1.1.12 lists the key protection systems that will be modeled in the planning studies. The Yolo Area (Woodland Substation) 115 kV Under-Voltage Load Shedding (UVLS) Scheme was placed into service by PG&E in July of 2007. This UVLS is designed to trip Woodland Circuit Switchers 116 and 126 to mitigate for unacceptable low voltages in the Yolo area due to the loss of the Brighton-Bellota 230 kV Line or overlapping loss of the Rio Oso-Woodland #1 and #2 115 kV lines during summer peak conditions. The CAISO identified a potential for voltage collapse following these contingencies in the Rio Oso Voltage Study dated June 19, 2007. Please add this project in "List of key protection system modeled in the study" (Table 9 on pages 15-17).

- ***Long Term Studies---***Section 1.1.16: below PG&E lists several areas within the PG&E service territory where a long term assessment of the transmission system is planned. The long term studies will consider system conditions ten years out and beyond in order to determine the load serving capability for the area and propose transmission upgrades to increase the area capacity and improve system reliability. PG&E would like to include these long-term studies in the 2010 Transmission Plan.

  - Bakersfield
  - Central Fresno
  - Cortina 60 kV
  - Henrietta/Corcoran
  - Ignacio-Mare Island 115 kV
  - Northern Fresno
  - Oakland
  - Paso Robles
  - Peninsula
  - Pueblo 115 kV
  - Tesla-Newark Corridor
  - Greater Bay Area

  In addition, PG&E recommends that the studies evaluating Greater Bay Area transmission system (OTC study, Greater Bay Area study, Oakland study and the Tesla-Newark Corridor study) need to be coordinated and that these studies should also evaluate various stakeholder proposals for reinforcing transmission paths into and within the Greater Bay Area. In doing so, a long-term overall plan for the entire Greater Bay Area transmission system would be effectively developed.

- Section 1.3.7, page 25: The first sentence in this section currently reads, “A tentative study schedule is proposed in Error! Reference source not found.1.” This sentence should be corrected.

<u>Conclusion</u>

Should you have any questions or thoughts please contact Mark Esguerra at PME8@pge.com or 415-973-4380.

Appendix A

Proposed Framework to address Fossil Generation Once Through Cooling Units

Analysis Requested: As an integral part of the California Independent System Operator's (CAISO) 2010 Transmission Plan, PG&E requests the CAISO's assistance in conducting a reliability study supporting the development of a specific plan to address the retirement or retrofit of once through cooling (OTC) units within PG&E's service area.

Objective of Analysis: The objective of the analysis that is to identify the alternatives available to replace OTC units. Alternatives could include transmission, demand-side or supply alternatives.

Proposed Analytical Approach: PG&E recommends developing and testing different scenarios with transmission and generation alternatives, taking into account demand reduction from energy efficiency and demand response programs. The scenarios should assess potential solutions for each area, or combination of areas that are interdependent, impacted by the removal of OTC units. Areas are defined as the following:

- Bay Area Units: Contra Costa 6 and 7, Potrero 3, Pittsburg 5 and 6
- Units that impact the Bay Area: Moss Landing 6 and 7; Moss Landing 1 and 2
- Independent Units: Morro Bay 3 and 4

A solution has already been identified to replace the once through cooling units at Humboldt; therefore PG&E recommends that this plant be removed from consideration for purposes of this study. Finally, replacement generation should not be located on the Peninsula due to the unlikelihood of future development in this area.

Baseline assumptions should include contracted generation that has been approved by the CPUC and is likely to be built and CAISO approved transmission upgrades and infrastructure additions that are likely to be completed. PG&E recommends that demand response and energy efficiency measures also be integrated into the baseline analysis. As energy efficiency is calculated for PG&E's entire service area, PG&E recommends that, as a simplifying assumption, forecast demand reduction from energy efficiency programs be allocated to the Bay Area proportional to the area's percent of PG&E's aggregate load.

With these assumptions in mind, the following analysis needs to occur, with a focus on the Bay Area:

For each scenario, assume that legacy OTC units are required to be retired and that Moss Landing units 1 and 2 are retrofitted by 2018.

- **Transmission-only Scenario:** For each area identify the transmission-only solution first in terms of cost, timeframe, and environmental impact. Identify where generation would need to be built to accommodate a transmission-only solution for the Bay Area. PG&E has already contracted for a study to identify transmission solutions, which was recently completed by Quanta Technology, LLC. The report is available for the CAISO's review and should inform this portion of the study.

- **Transmission and Generation Scenarios:** Add a generic 500 MW of new generation to the Bay Area incrementally and estimate the residual transmission needed. Place the new generation at different locations in order to test any sensitivities. In particular, the sensitivities around the Pittsburg and Contra Costa sub-areas should be analyzed.
- **Generation-only Scenario:** Define a generation-only alternative where the OTC generation, with the exception of Potrero unit 3, is repowered or replaced in the same or an equivalent site.

Upon completion of the OTC Study, the alternatives can be compared in terms of cost, time, and environmental impacts. PG&E welcomes the CAISO's input on this proposed analytical framework.

ATTACHMENT K

California ISO
Your Link to Power

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Laura Manz, Vice President of Market and Infrastructure Development

Date: March 18, 2009

Re: **Briefing on 2009 ISO Transmission Plan**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

The purpose of this memorandum is to provide the ISO Board of Governors (the Board) with an overview of the *2009 ISO Transmission Plan* (Transmission Plan). The Transmission Plan consists of four major components:

- A summary of the results of various technical studies conducted by the ISO during the planning cycle;
- A detailed discussion of the contingency conditions and the mitigation plans proposed by the ISO;
- A description of the new projects and study proposals submitted through the request window, as well as the projects approved by ISO Management that represent more than $390 million in transmission infrastructure investment; and
- A roadmap to the 2010 annual study and planning cycle, including a discussion of the key initiatives that will shape the upcoming planning process.

The 2009 Transmission Plan will also serve to demonstrate how the ISO is ensuring the reliability of the ISO Controlled Grid through its assessment of the North American Electric Reliability Corporation's (NERC) planning standards with which the ISO is obligated to demonstrate compliance. Finally, this Transmission Plan has been structured to meet the transmission process requirements described in the ISO's *Business Process Manual for Transmission Planning* (BPM) developed to comply with the transmission planning principles outlined by the Federal Energy Regulatory Commission in Order 890.[1]

[1] *Preventing Undue Discrimination and Preference in Transmission Service* , 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs., ¶ 31,241 (2007), *order on reh'g and clarification,* Order No. 890-A, 73 Fed. Reg. 2,984 (Jan. 16, 2008), FERC Stats. & Regs., Regs. Preambles ¶ 31,261 (2007); *order on reh'g and clarification,* Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008).

The planning process is a collaborative effort among the ISO, participating transmission owners and other stakeholders. During 2008, the ISO sponsored three stakeholder meetings to collect input on the transmission plan:

- The first was held on March 10, 2008, where the overall study plan was presented, including the unified planning assumptions that were to be used in the studies;
- The second was held on November 20, 2008, where ISO staff presented and discussed all study results and presented new transmission projects identified as appropriate solutions to system needs; and
- The third was held on February 27, 2009, where ISO staff presented the *Draft 2009 Transmission Plan* to stakeholders.

Based on comments received from stakeholders at the February 27, 2009 meeting, ISO staff made clarifying revisions to draft plan presented at that meeting and prepared a *Final Draft 2009 ISO Transmission Plan*. Due to the size of the document, a copy is available upon request. Please refer to Attachment A for the detailed stakeholder matrix.

FINDINGS AND TRANSMISSION PROJECTS

The reliability studies necessary to ensure compliance with NERC planning standards are the foundation of the Transmission Plan. During 2008, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure compliance with NERC reliability standards TPL-001 through TPL-004. The analysis was performed across a ten-year planning horizon using summer on-peak/off-peak system models. As a result of this analysis, over 200 criteria violations were identified across a voltage bandwidth of 60kV to 500kV; for which the ISO proposed over 160 mitigation plans to address these violations.

It is ISO's responsibility to lead and manage the transmission planning process to ensure coordinated planning across the ISO controlled grid. As such, the ISO is uniquely positioned to perform, or cause to be performed, all necessary studies required to meet NERC reliability standards. Thus, the ISO performed an exhaustive analysis of the ISO controlled grid, identified future needs, and proposed mitigation plans to address these identified needs. The ISO posted and presented its results to stakeholders in November 2008. All stakeholders were invited to submit, into the 2008 request window, alternative proposals to those developed by the ISO. This is a necessary action as FERC's Order 890 comparability standard requires that the ISO's planning process only consider projects submitted through its request window.

At the close of the 2008 Request Window, the ISO had received 134 proposals for consideration in the ISO's planning process. The following table provides a description of how the ISO handled the Request Window proposals.

Disposition of Request Window Submittals

Proposals Received	ISO Screening Result
45	Approved by ISO Executive Management
2	Approved by ISO Executive Management for Board consideration in 2009
11	Study requests for analysis in the 2009 transmission planning process
31	Conceptual
33	Require additional information and evaluation
12	Withdrawn or rejected

It is important to note that the 45 proposals approved by ISO Management were submitted in response to the ISO's determination of reliability needs of the ISO Controlled Grid. In total, these proposals represent an investment of more than $390 million in infrastructure additions to the grid.

While the transmission plan has a predominate focus on reliability compliance, ISO staff was also involved in a number of other key initiatives during the year. In some cases, these initiatives required advanced and/or specialized studies to complete.

- Preliminary renewable transmission plans for meeting 20% and 33% RPS goals;
- Transmission impacts due to regulations regarding once through cooling power plants;
- 2010 probabilistic planning reserve margin study in conjunction with the California Public Utility Commission's rulemaking proceeding process using GE's multi-area reliability simulation program[2];
- Small signal stability analyses for the ISO and WECC areas using Powertech Labs Inc. dynamic security assessment software;
- Optimizing dynamic and static reactive support for the Tehachapi transmission project; and
- Preliminary locational marginal pricing study using Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee's 2017 base case.

On balance, this transmission plan formulates the backdrop for a system expansion plan that benefits all Californians within the ISO footprint. Future iterations of the transmission plan will reflect market drivers such as nodal prices and long-term transmission rights as a consideration for grid enhancement.

[2] *Order Instituting Rulemaking to Consider Revisions to the Planning Reserve Margin for Reliable and Cost-Effective Electric Service* R.08-04-012.

ATTACHMENT L

Market Notice

June 8, 2009

California ISO
Your Link to Power

Categories
Grid Operation
ISO News and Information
Legal/ Regulatory

Requested Client Action
Information Only

Amended ISO 2009 Transmission Plan

Summary
The amended 2009 ISO Transmission Plan is now available on the ISO website at http://www.caiso.com/2354/2354f34634870.pdf.

Main Text
During the March 24, 2009 stakeholder meeting, the California ISO (ISO) informed stakeholders that some projects submitted through the 2008 request window were not eligible for approval at the time the 2009 Transmission Plan was developed because further information was required from project proponents. These projects are listed on Table 1-3 of the plan as "Ongoing Projects Requiring Further Information or Evaluation." The ISO advised stakeholders that, for certain projects, it anticipated the evaluation process could be promptly concluded and that these projects could proceed to approval as part of the 2008 transmission planning process. Completion of the evaluation process for certain projects would necessitate an amendment to the 2009 Transmission Plan.

The ISO has completed its assessment of some projects identified in Table 1-3, and has set forth the results of its evaluation in the amended 2009 ISO Transmission Plan, available at http://www.caiso.com/2354/2354f34634870.pdf. For more information regarding the changes, please refer to summary of changes shown on page 298 of the amended plan.

For More Information Contact

Paul Didsayabutra at pdidsayabutra@caiso.com or Dana Dukes at ddukes@caiso.com

The California ISO strives to be a world-class electric transmission organization built around a globally recognized and inspired team providing cost-effective and reliable service, well-balanced energy market mechanisms, and high-quality information for the benefit of our customers.

151 Blue Ravine Road, Folsom, CA 95630

EA/ComPR/IPS/cy

ATTACHMENT M

4.5.3.3 Recommended solutions for reliability criteria violations

- **Burney 60 kV line voltage-Category A**

The Burney QF to Burney section of the Pit #1-Hat Creek #4-Burney 60 kV line appear to have an overload in error; PG&E to verify model.

- **Wyandotte 115 kV Tap-Line-Category A**

The Wyandotte-Wyandotte Junction section of the Palermo-Caribou 115 kV line will overload starting in 2018 at present load growth. Solution could include re-rate, re-conductoring or load transfer. Another solution would be to loop this substation since its load is above 60 MW and PG&E's own guideline states that substations above 50 MW should be looped in.

- **Plumas-Sierra low voltage-Category A and B**

Voltages in Plumas-Sierra service territory are constantly low for both 2013 and 2018 cases. Also the loss of the Caribou-Plumas Junction 60 kV line is divergent due to the same voltage support issue. Solution could include voltage support and/or new interconnection with stronger voltage source.

- **Chico area reinforcement-Category B and C**

Numerous potential overloads for category B and C conditions as well as voltage deviation at Sycamore. Solution could include Special Protection Scheme (SPS) plus line re-conductoring and/or rearrangement or a new Double Circuit Tower line (DCTL) from Table Mountain or new connection with from another strong source to Sycamore.

- **Trinity area reconfiguration-Category B and C**

Numerous potential overloads for category C and voltage deviation for category B and C. The mitigation plan is to reconfigure the Trinity 60 kV system and/or implement new emergency operating procedures in this area.

- **Cascade area reinforcement-Category B and C**

The local power plants include hydroelectric facilities on Battle Creek (50 MW) and Olsen Cogeneration (9.5 MW). In addition to the internal generation above, the Cascade substation has a connection to PacifiCorp that operates in northern California and other western states. These imports, the local generation and the Cascade 115/60 kV Transformer No. 1 are the key power supply facilities.

Multiple potential overloads for category B and C conditions as well low voltage and voltage deviations can be mitigated by installing another transformer at Cascade as well as miscellaneous re-conductoring and system rearrangement for the 60 kV systems in this area. Also a different alternative would be to move some of the loads in this area to the 115 or 230 kV systems.

- **Deschutes area reconfiguration and voltage support-Category B and C**

The local power plants include hydroelectric facilities on Battle Creek (50 MW) and Olsen Cogeneration (9.5 MW).

Multiple potential overloads for category B and C conditions as well low voltage and voltage deviations can be mitigated by reconfiguring the system and installing voltage support or by moving some of these loads to the 115 kV or 230 kV system.

- **Red Bluff long-term reinforcement-Category B and C**

There is only one local power plant Neo Red Bluff Peaking Plant (50 MW). Sensitivity analysis concluded that an outage of the Neo Red Bluff Peaking Plant would cause a voltage deviation of more than 10% at the Tyler and Rawson local 60 kV substations.

ATTACHMENT N

PacifiCorp that operates in northern California and other western states. These imports, the local generation and the Cascade 115/60 kV Transformer No. 1 are the key power supply facilities. Multiple existing potential overloads, as well low voltage and voltage deviations for category B and C conditions, can be mitigated by installing another transformer at Cascade as well as miscellaneous reconductoring and system rearrangement for the 60 kV systems in this area. A different alternative would be to move some of the loads in this area to the 115 or 230 kV systems. Most feasible project implementation due to permitting and lead times is 2014. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Deschutes Area Reconfiguration and Voltage Support-Category B and C
The local power plants include hydroelectric facilities on Battle Creek (50 MW) and Olsen Cogeneration (9.5 MW). Multiple existing potential overloads, as well low voltage and voltage deviations for category B and C conditions, can be mitigated by reconfiguring the system and installing voltage support, or by moving some of these loads to the 115 kV or 230 kV system. Most feasible project implementation due to permitting and lead times is 2015. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Trinity Area Reconfiguration-Category B and C
Numerous potential low voltages and voltage deviations for category B and C can be mitigated by reconfiguring the Trinity 60 kV system and/or implement new emergency operating procedures in this area. Western Area Power Administration (WAPA) together with Trinity PUD have a common project with expected operational date of April 1, 2010 that will move the TPUD load to the WAPA's system, therefore mitigating the reliability concerns. In the interim load shedding will be used for category B and C conditions.

Upgrade Cottonwood 60 kV bus to BAAH Arrangement-Category C
Potential existing local voltage collapse and overloads on the Cascade-Oregon Trail section of the Cascade-Benton-Deschutes 60 kV line is expected for the Cottonwood bus outage. Solution could be to upgrade the Cottonwood 60 kV bus from main and aux to BAAH arrangement. Most feasible implementation due to lead times is 2013. In the interim load shedding will be used for this category C condition. This plan will be assessed further and included in the next annual ISO transmission plan.

Chico Area Reinforcement-Category C and D
Numerous existing potential overloads for category C and D conditions. Solution could include Special Protection Scheme (SPS), plus line reconductoring and/or rearrangement or a new Double Circuit Tower line (DCTL) from Table Mountain or new connection from another strong source to Sycamore. Most feasible project implementation due to lead times is 2011. In the interim load shedding will be used for this category C condition. This plan will be assessed further and included in the next annual ISO transmission plan.

3.3.3.5 Key Conclusions

Based on the ISO reliability assessment, the North Valley area had:

- Two overloads and one worst low voltage under normal conditions;
- Seven overloads caused by nine critical contingencies as well as four worst buses with low voltages caused by five critical contingencies and six worst voltage deviations caused by six critical contingencies under single contingency conditions; and
- Four divergent cases, 15 overloads caused by 20 critical contingency conditions as well as eight worst buses with low voltages caused by 10 critical contingencies and seven worst voltage deviations caused by nine critical contingencies under multiple contingency conditions.

In order to address the identified overloads, the ISO proposed a total of 10 transmission solutions. The ISO received four project proposals through the request window.

ATTACHMENT O

2010 ISO Transmission Plan Stakeholder Next Steps

Gary DeShazo

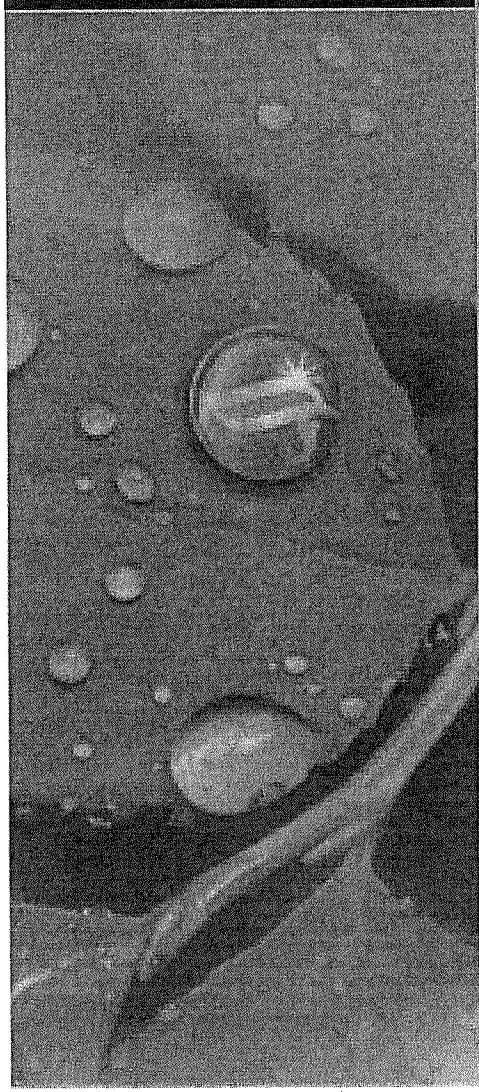
Director, Regional Transmission North

February 16, 2010

Next Steps

- Comments Due to regionaltransmission@caiso.com on March 2, 2010
- Post draft final 2010 ISO Transmission Plan second week of March 2010
- Present 2010 Transmission Plan to ISO Board of Governors March 25 and 26
- Post final 2010 ISO Transmission Plan last week of March 2010

ATTACHMENT P



California ISO
Your Link to Power

2010 CAISO Transmission Plan
1st Stakeholder Meeting

Paul Didsayabutra
Senior Regional Transmission Engineer

David Le
Lead Regional Transmission Engineer

Market & Infrastructure Development

March 24, 2009

Objectives

- Discuss
  - The technical studies proposed to be conducted in 2009
  - Study assumptions and methodology of each study
  - Other major activities
- Seek input from stakeholders
- Outline major milestones, timeline
- Planning data, availability of information

Other ISO annual studies and Next Steps

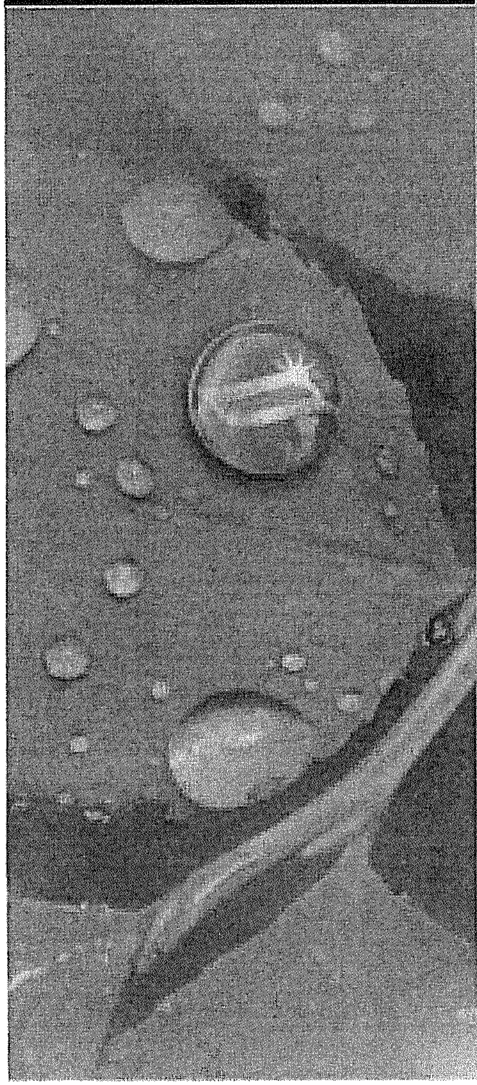
- **Long-term LCR**
  - 2012
  - 2014
- Stakeholder comments due - April 7, 2009
- Please submit your comments to regionaltransmission@caiso.com
- Study Plan finalized - April 21, 2009
- Posting of planning data – April 2009

Reliability Assessment (Southern Area)

- The system will be evaluated under normal and emergency conditions based on NERC, WECC and CAISO Planning Standards
- The following contingencies will be studied
  - Loss of single element (Category B) e.g. G-1, L-1, T-1, L-1/G-1
  - Loss of two or more elements (Category C) e.g. DCTL, C-3
  - Extreme contingencies
    - Lugo Substation Outage (One voltage level plus transformers)
    - North of Miguel common corridor outage (combined 230kV, 138kV and 69kV line outages)
    - Loss of 3 lines South of WECC Path 26

California ISO
Your Link to Power
10 Year Anniversary

2010 CAISO Transmission Plan Send Stakeholder Meeting



Jim Blatchford

Senior Policy Issue Representative

October 26-27, 2009

Where Are We?

2010 CAISO Transmission Plan

We are here

Unified Planning Assumption Meeting
March 24 '09

Posted Final Study Plan
May 14, '09

Request Window Opens
Aug 15, '09

Study Results Posted
Sept 15, 09

Study Results
S/H Meeting
Oct 26, 27 '09

Request Window Closes
Nov 30, '09

S/H Comments Due
Nov 10, '09

Post 2010 Draft CAISO Transmission Plan
Jan 28, '10

Stakeholder Meeting
Feb 16, '10

Final Comments Due
Mar 2, 10

Board Of Governors
Mar 2010

Opportunities for Stakeholder Input

Stage 2 of the 2010 ISO Transmission Planning process is nearing completion

California ISO
Your Link to Power

The ISO is seeking stakeholder input on technical study results and project proposals

- Day 1 (all day) – ISO Technical Study Analysis Results
  - Reliability Assessment
  - Long-Term CRR
  - ISO Short-Term Plan
  - Greater Bay Area Long-Term Study
  - 2020 Renewable Transmission Conceptual Plan
  - 2010 Economic Planning Study – Congestion Evaluation
- Day 2 (morning) – IOU Project Proposals
- Day 2 (afternoon) – Status of C3ET Project Analysis
- Within two weeks – Stakeholder comment/input due

Next steps, Major Milestones

Activity	Date
Stakeholder Comments Due	11/10/2009
2009 Request Window Closes	11/30/2009
ISO Posts Draft 2010 Transmission Plan	January, 2010
3rd Stakeholder Meeting	February, 2010
Stakeholder Comments Due	February, 2010
Present to ISO Board of Governors	March, 2010

- Please email your comments to *regionaltransmission@caiso.com*

ATTACHMENT Q

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Host's Name:	THOMAS CUCCIA
Name of Conference:	2010 TRANSMISSION PLAN
Date of Conference:	TUESDAY, FEBRUARY 16, 2010 10:00 AM PACIFIC

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18.	FLYNN, BARRY	FLYNN RCI	888 634-7516
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22.	JENKINS, ROBERT	FIRST SOLAR	510 625-7435
23.	KAPLAN, KATIE	IES	925 314-7800
24.	KRITIKSON, JIM	KRITIKSON & ASSOCIATES	909 480-1028
25.	KRUGER, VICTOR	SDG & E	858 654-1619
26.	LINDHOUT, TREVOR	C O P	281 293-6844
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ATTACHMENT R

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March 2, 2010

VIA EMAIL

Mr. Keith Casey
V.P. of Market & Infrastructure Development
California ISO
151 Blue Ravine Road
Folsom, CA 95630

Mr. Gary DeShazo
Director, Regional Transmission North
California ISO
151 Blue Ravine Road
Folsom, CA 95630

Dear Sirs:

Western Grid Development LLC ("WGD") hereby responds to the Transmission Plan Stakeholder Meeting Overview that the California Independent System Operator, Inc. ("CAISO") held on February 16, 2010. WGD respectfully disagrees with the decision to reject all eight (8) of WGD's proposed reliability network upgrades ("WGD Projects") [1]. The reasons for rejecting the WGD Projects, as set forth in the Draft 2010 California ISO Transmission Plan distributed in February of 2010 ("Plan"), are: (1) technically flawed; (2) not supported by sufficient record evidence; and (3) arbitrary and capricious, as well as contrary to the Federal Energy Regulatory Commission's ("FERC") Order No. 890 transmission planning policies. The Summary of Errors in the Plan which follows describes the primary examples of why the Plan's conclusions regarding the WGD Projects should be reversed.

FERC's Order No. 890 and effective public policy requires that utility-proposed alternatives be judged using the same technical and economic criteria, along with comparisons of

[1] Tulucay, Stockton, Madison, Auburn, Potrero, Guernsey, Coppermine, & Weedpatch.

WAS:158942.1

the time necessary for completion, as non-utility proposals.[2] There is no advantage to ratepayers for utilities to be granted a right of first refusal for any network upgrades, including reliability projects. On the contrary, without the prospect of open competition for reliability projects, ratepayers may be forced to pay for projects that are technically inferior, more expensive, and take longer to complete than non-utility alternatives. Such a result is inconsistent with Order No. 890; it is a concept that FERC has not endorsed in Order No. 890, and there are no public policy arguments for such an outcome.

WGD is also enclosing detailed Exhibits for each of the WGD Projects which: (a) describes the relevant reliability problem; (b) review the Plan's proposed solution; (c) describe the Plan's proposed costs; (d) provide the Plan's implementation timeframe; (e) discuss the WGD solution; (f) provide the WGD Project cost; (g) summarize the Plan's conclusion; and (h) discuss the flaws in the Plan's conclusions.

EXECUTIVE SUMMARY

In accordance with CAISO Transmission Open season, and consistent with FERC 890 order, and based on previously identified reliability violation at specific locations by the CAISO, WGD filed eight (8) Energy Storage Devices ("ESD") projects, complete with reliability and economic analysis, to be constructed and operated at specific sites along the CAISO grid. The WGD projects were designed to address existing and forecasted reliability violation posted by the CAISO on September 15, 2009. The WGD projects were proposed to be either an alternative solution to the local Participating Transmission Owner ("PTO") proposal or a proposal with no alternative solutions identified on January 21, 2010. WGD's Projects will be used to provide voltage support and to address thermal overload situations at the CAISO's instruction. WGD's proposed ESD uses an advanced transmission technology that has a smaller adverse environmental impact than traditional transmission solutions, can provide efficient transmission solutions for existing reliability problems, and can be incorporated into the CAISO system using smart grid technologies[3].

As described in detail below and in the enclosed Exhibits, the Plan contains numerous significant technical errors regarding the relative merits of the WGD Projects.[4] In addition, the Plan contains conclusions that are not supported by record evidence.[5] Finally, the Plan contains

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2 Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241.

3 WGD proposed to use a sodium sulfur (NaS) batteries, similar to the PG&E NAS 4 MW demonstration project under way in San Jose, California.

4 In evaluating WGD's Coppermine Project, for example, the Plan stated that an outage of the Borden-Coppermine 70kV line plus Friant Gen should be considered a "category D contingency and does not require mitigation"; the CAISO's Final 2009 Transmission Plan, however, stated that this same outage was a Category B outage, which would create a 119% overload rating by 2013.

5 In evaluating WGD's Tulucay Project, for example, the Plan concluded that WGD's Project would "not significantly reduce LCR [local capacity requirement] since it relieves overload only on one bottleneck" without providing any record evidence to support this conclusion. In

numerous conclusions that are simply arbitrary and capricious, and inconsistent with FERC's Order No. 890.

Equally importantly, the Plan is flawed because it ignores the significant savings that ratepayers would receive if the WGD Projects were implemented to address the subject reliability concerns. The enclosed Exhibit 1, based upon data submitted by WGD in response to the Plan, compares the costs of the Plan's projects to address each of the eight (8) reliability problems to the costs that ratepayers would pay if the WGD Projects were selected. Even if one conservatively assumes that WGD would have the same rate design as Pacific Gas & Electric Company ("PG&E"), the WGD Projects would save ratepayers a total of over $100 million. If one assumes that WGD will construct and operate the WGD Projects, the savings to California ratepayers is estimated to exceed **$522 million.**

SUMMARY OF THE ERRORS IN THE PLAN

1. The Plan's Conclusions Are Technically Flawed

As detailed in the enclosed Exhibits, the Plan rejected the WGD Projects based upon numerous technical errors and inconsistencies. For example, the Plan stated that an outage of the Borden-Coppermine 70kV line plus Friant Gen should be considered a "category D contingency and does not require mitigation".[6] The CAISO's Final 2009 Transmission Plan, however, stated that this same outage was a Category B outage, which would create a 119% overload rating by 2013.[7] There is nothing in the Plan which would explain why the Plan had somehow transformed a Category B contingency to a Category D contingency.

CAISO reported a reliability violation at Tulucay in the North Coast. The reliability violations have existed for more than three years and no remedial proposal was submitted to CAISO. WGD submitted an ESD project to address this reliability violation. The Plan reported that an alternative proposal to "drop load in the south Geysers area" and "open-up two transmission lines" is the Plan's preferred solution.[8] The Plan does not explain if this is a preferred solution, why a reliability violation has been reported in the last three years and how "dropping load" would be considered a superior alternative than WGD Proposal.

WGD proposed to resolve reliability violations at two locations where the CAISO identified reliability violation level A (Guernsey and Madison) at significantly lower cost that competing solutions.[9] The Plan indicated that the ESD at Guernsey impacts Helms pumping and

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contrast, WGD presented evidence that the Tulucay Project will initiate immediately when there is an overload; it is unclear how WGD's proposed solution does not directly reduce LCR.

6 Plan, p. 181.

7 *http://www.caiso.com/1ca5/1ca5d8334b920.html*, Page 137.

8 Plan, p 69.

9 WGD proposed solution has a significantly lower cost to California ratepayers. WGD estimates that the total Net Present Value cost savings are $134 million, $34 million and $27 million for the Auburn, Guernsey and Madison Projects, respectively

the proposed PG&E solution (although at "unknown cost") is "simpler" and "cost effective."[10] The Plan does not explain how an ESD of 3 MW that operates only few hours a year can possibly adversely impact a 1000 MW pump.

For the Madison site, CAISO indicated that it has recently received a new proposal from PG&E to "re-rate the line."[11] The Plan states that the re-rate of the line and the re-conductoring proposal of the line is a superior solution, but the Plan offered no reliability or economic justifications.[12] The Plan erred technically by failing to take into account the staged approach of the WGD projects versus the initial large capital cost of PG&E proposal, in particular that the incremental approach proposed by WGD maintains reliability while lowering the cost to ratepayers.

The WGD Madison Project was also rejected because the Plan inexplicably concluded that "there is no need for this project, or any other transmission upgrade or addition, because the Vaca-Madison 115kV line can be rerated at minimal cost."[13] This conclusion is technically flawed because the Plan <u>also</u> concluded that this line would exceed 100% of its loading and thus would require relief.[14] Reasonable minds can differ about proposed engineering decisions; however it is erroneous for the Plan to simply "rerate" a line that is facing overload, rather than address adoption of a least-cost remedy.

2. *The Plan's Conclusions Are Not Supported by Record Evidence*

The Plan's conclusions regarding the WGD Projects should be reversed, in part because they are not supported by sufficient record evidence. For example, in evaluating WGD's Tulucay Project, the Plan concluded that WGD's Project would "not significantly reduce LCR [local capacity requirement] since it relieves overload only on one bottleneck"[15] without providing any record evidence to support this conclusion. In contrast, WGD had presented convincing evidence that the Tulucay Project would initiate immediately when there is an overload; it is unclear how this solution does not directly reduce LCR. Moreover, it is illogical for the Plan to suggest that the WGD energy storage device reduces flow on the limiting element, but will not also reduce flows on a parallel Vaca Dixon-Lakeville 230kV line. This conclusion goes against basic load flow principles. The Plan also concludes that the cost of the Tulucay Project is "comparable" to a competing proposal to reconductor the relevant lines, without providing <u>any</u> estimate of the reconductoring costs.[16]

WGD proposed an ESD at Auburn area where CAISO reported a reliability violation level A. The PG&E proposed solution is to re-conductor the area, at a capital cost of $50 million

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10 Plan, pp 174-175.

11 Re-rating a line is a practice that is used as a last tool and is not a permanent solution nor it's a solution that was proposed prior to the deadline.

12 Plan, p 126.

13 Plan, p 126.

14 *http://www.caiso.com/2738/2738128a83260.pdf*, Page 93.

15 Plan, p. 70.

16 Plan, p. 69.

to $60 million as reported by CAISO on September 15, 2009. The Plan denied WGD's project, even though the proposed WGD solution is a reliable alternative with Net Present Value ("NPV") net savings to ratepayers of $134 million.

As described in detail on Exhibit 1, the WGD Projects would enable the CAISO to fulfill its obligation to provide lowest cost solution to ratepayers, consistent with its Tariff and FERC Order No. 890. In fact, the Plan repeatedly rejects the WGD Projects as not being least-cost alternatives, without justifying such erroneous economic conclusions. As shown on enclosed Exhibit 1, seven (7) of the eight (8) WGD Projects are significantly less expensive than the PG&E alternatives, even if one conservatively assumes that WGD's Operating & Maintenance ("O&M") costs will be comparable to PG&E's O&M costs. If one recognizes that WGD's O&M costs are expected to be much lower than PG&E's O&M costs (due to WGD's significantly lower overhead), all eight of WGD's Projects are the least-cost projects to resolve the subject constraints that CAISO identified. This cost comparison reveals that California ratepayers could save over $520 million if the Plan permitted WGD to resolve these eight reliability problems!

3. The Plan's Conclusions are Arbitrary and Capricious and are Contrary to Order No. 890

The Plans conclusions should also be rejected because they are in several instances arbitrary and capricious and without a logical basis. The Plan illogically rejected the Tulucay Project, for example, because Section 24.1.2 of the CAISO Tariff provides that PTOs have an obligation to build, own and maintain. The Plan rejects the WGD reliability solutions, in part, because WGD is not a PTO.[17] This is an arbitrary conclusion, not only because it is premature for the Plan to conclude that WGD cannot qualify as a PTO (WGD has not yet applied for PTO status) but because the CAISO has advised other potential PTOs that they cannot qualify to become a PTO until <u>after</u> they have had a Project approved in the Plan.[18] This sort of "chicken and egg" rationale for denying the WGD Projects (*i.e.*, a party cannot have its Project approved by the Plan because the party is not yet a PTO, however the CAISO will deny PTO status to any party that does not have an approved Project under the Plan) demonstrates that the Plan's conclusions in this regard are fatally flawed.

WGD proposed two ESDs to resolve a reliability violation in San Francisco and the Weedpatch area of the central valley. The Plan denied these two projects based on the claim that San Francisco has no reliability violation and that the reliability violation at Weedpatch can be resolved by opening Circuit Breaker 42. This information directly conflicts with the report on

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17 Plan, p. 69. (The Plan employed a similar argument at p. 125 for WGD's Stockton Project).

18 For example, in a December 3, 2009 letter to a prospective PTO, Transmission Technology Solutions, Duane Kirrene from the CAISO rejected a request to become a PTO stating, in part, that the "definition of a "Participating TO" and the provisions of Section 2.2.3(iv) and 2.2.5 of the Transmission Control Agreement are based on the premise that <u>an entity cannot become a participating transmission owner until FERC has approved its transmission owner tariff and it has facilities in service over which the ISO has accepted operational control</u>." (emphasis added).

September 15, 2009, which concluded that San Francisco will need 25 MW to comply with the reliability criteria post-Trans Bay cable. In contrast, the Plan reported that the load in area is lower than previously forecast, without explaining this significant change. Because the Plan is based upon the assumptions listed in the September 15, 2009, report, any change in the assumptions must be applied to all projects. The Plan does not demonstrate that load adjustments were equally applied to all projects. Moreover, the Plan does not explain what information was received to make this change since September. In addition, if the new assumptions are correct and San Francisco now is not expected to have any reliability violation, it is unclear why the Potrero gas turbines 5, 6 and 7 will still be needed.

WGD proposed an ESD to solve the previously identified reliability violation level B at Stockton. The Plan concluded that PG&E re-conductoring proposal coupled with "re-rating of the line" is superior due to lower cost than WGD.[19] As discussed above, the project cost for the PG&E proposal were not reported in the Plan, even though costs for the competing WGD Projects were reported and posted on CAISO Web.

CONCLUSION

WGD respectfully requests that CAISO carefully consider the arguments raised herein and in the enclosed Exhibits, and then reconsider its decision to reject all eight of WGD's proposed reliability network upgrades.

Respectfully Submitted,

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Counsel for Western Grid Development, L.L.C.

Enclosures

cc: Nancy Saracino - General Counsel

[19] Plan, p 125.

WAS:158942.1

EXHIBIT 1

Comparison of Cost Savings to Ratepayers of WGD's Projects vs. Plan Proposals

WGD used the following 2007 PG&E published rates:[20]

PG&E 2007 RATES	$x1000	% of Revenue Requirement	% ratebase
Transmission O&M	124,881	18.67%	4.8%
A&G	60,991	9.12%	2.4%
Proprety Tax	31,093	4.65%	1.2%
Payroll Tax	6,377	0.95%	0.2%
Other taxes	348	0.05%	0.0%
Depreciation	132,036	19.74%	5.1%
Revenue Credits	(13,066)	-1.95%	-0.5%
Subtotal	342,660	51.22%	13.3%
		0.00%	0.0%
Franchise fees	5,409	0.81%	0.2%
Return	225,561	33.72%	8.8%
FIT	74,285	11.10%	2.9%
State IT	21,070	3.15%	0.8%
Subtotal	326,325	48.78%	12.7%
Total Rate Base	2,577,838		
ROR	8.75%		
Total Rev Req	668,985	100.00%	

WGD rates for O&M and A&G are 1/3 of PG&E rate. The economic benefits of implementing the WGD solutions are summarized below. The Table below shows the estimated cost of both the WGD and PG&E solution both based on WGD rate and PG&E filed rate. Under both condition, ratepayers are benefiting from WGD proposal.

Site Number	Site Name	PG&E Project Cost (NPV)	WGD Project Cost (NPV), Using WGD Proposed Rates	Savings to Ratepayers	Estimated Initial Capital Cost ($M)
1	Tulucay	$ 207,097,355	$ 129,755,899	$ 77,341,456	Assumed project cost of $40 Million
2	Stockton	$ 207,097,355	$ 136,139,971	$ 70,957,385	Assumed project cost of $40 Million
3	Madison	$ 72,484,074	$ 27,083,549	$ 45,400,526	Assumed project cost of $14 Million
4	Auburn	$ 284,758,864	$ 134,242,021	$ 150,516,843	PG&E listed cost between $50-60 Million
5	Potrero	$ 150,145,583	$ 92,636,582	$ 57,509,001	Assumed project cost of $29 Million
6	Guernsey	$ 77,661,508	$ 46,621,400	$ 31,040,109	PG&E listed cost between $10-$15M
7	Coppermine	$ 207,097,355	$ 106,321,201	$ 100,776,155	PG&E listed cost $25-$40 Million
8	Weedpatch	$ 62,129,207	$ 39,045,563	$ 23,083,644	Assumed project cost of $12 Million
Total	Total	$ 1,268,471,302	$ 711,846,185	$ 556,625,117	

[20] Filing with the FERC, Pacific Gas & Electric Company, Transmission Owner Tariff, 2009. Exhibit PGE-22, Workpapers Supporting Exhibit PGE-3, Unbundled Revenue Requirement.

EXHIBIT 2

Tulucay 60kV:

a. Description of Problem:

The CAISO 2010 Local Capacity Technical Analysis Final Report and Study Results (May 2009) for the Lakeville Sub-area states:

> "**Lakeville Sub-area**
> The most limiting contingency is the outage of Vaca Dixon-Lakeville 230 kV line with DEC power plant out of service. The sub-area limitation is thermal overloading of the Vaca Dixon-Tulucay 230 kV line. This limiting contingency establishes a LCR of 787 MW (includes 18 MW of QF and 131 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area."
> (*http://www.caiso.com/23a1/23a186dd41f50.pdf*, Pages 30-31)

The 2010 California ISO Transmission Plan (*February 2010*) includes a summary of thermal overloads for summer peak conditions for the North Coast and North Bay areas. The CAISO transmission plan indicates the issues in this region by stating:

> "Vaca Dixon - Lakeville Ckt #1 and Tulucay - Vaca Dixon Ckt #1 230 kV Lines
> The proposed solution to mitigate these category C overloads is to develop or modify an existing operating procedure to drop the load in the south Geysers area or open these 2 lines under contingency conditions, The study results show that this mitigation plan is needed in 2010 and it could require lead time of several months to develop the operating procedure. In addition, it is possible that the identified overloads can also be alleviated by accelerating the construction of several transmission projects that CAISO have previously approved.
> The ISO reliability study results show that mitigation plans are needed for potential overloads on 1) Vaca Dixon – Lakeville and 2) Vaca Dixon - Tulucay 230 kV Lines. In addition, the ISO LCR study results also show that the Vaca Dixon - Tulucay 230 kV line is the limiting facility that drives LCR requirements in the North Coast/North Bay area."
> (*http://www.caiso.com/2738/2738128a83260.pdf*, Page 69)

b. Proposed Plan Solution:

The 2010 California ISO Transmission Plan (*February 2010*) states that the CAISO recommended solution is to develop operating procedure or load dropping scheme (http://www.caiso.com/2738/2738128a83260.pdf, page 51).

c. Proposed Plan Solution Cost:

Unknown. The cost of the CAISO proposed solution is not included in the 2010 California ISO Transmission Plan (February 2010)

d. Plan Timeframe: 2010

e. Proposed WGD Solution:

Install a 25MW battery storage device at Tulucay 60kV substation in 2011. Study suggests a reduction in LCR of 42MW.

f. WGD Solution Cost:

Initial Capital cost is $37.5M. The NPV for the project is $201.2M (This includes taxes, O&M, A&G, etc).

g. CAISO Draft Response:

The Plan denied the WGD projects based on the following:

- WGD has no obligation to build, own and maintain reliability-driven projects
- Does not mitigate parallel Vaca Dixon-Lakeville 230kV Line
- Cost is more than reconductoring both Vaca Dixon-Lakeville and Vaca Dixon-Tulucay 230kV Lines
- Reconductoring projects is a better long-term solution
- Reconductoring will reduce LCR requirements that Battery would not (*http://www.caiso.com/2738/2738128a83260.pdf*, page 69)

h. WGD Comments and Questions:

The Plan does not describe clearly how the subject overload will be resolved without the WGD Project. The Plan cites two different solutions to the problem. The Plan recommends, on one hand, an inferior load dropping scheme that will result in decreased system reliability. Then, as if the Plan was confused that it had already made a recommendation, the Plan suggests another resolution which is to reconductor the overloaded lines. The Plan gives no supporting evidence or economic data to support the claim that the reconductor alternative is a cheaper approach. The Plan then states that the reconductor project is a "better" long term solution even though the studies conducted by ZGlobal and presented to the CAISO clearly determined a battery size that would support long term load growth. The Plan incorrectly states that LCR's will not be reduced by the battery project, but LCR will be reduced by reconductoring. The battery is a reliability project that will initiate immediately when there is an overload; it is unclear how this solution does not directly reduce LCR. Finally, it is illogical to suggest that the battery reduces flow on the limiting element, but will not reduce flows on a parallel Vaca Dixon-Lakeville 230kV line. This goes against basic load flow principles and this statement needs to be clarified by the Plan.

Exhibit 3

Stockton 60kV

a. Description of Problem:

The 2010 CAISO reliability assessment results (September 2009) and the 2010 California ISO Transmission Plan (*February 2010*) identified that loss of the Stockton A-Weber #2 60kV line and Stockton Wastewater would cause Stockton A-Weber #1 60kV line to overload to 107% of the emergency rating by 2014 (CVLY-T-087).

ID	Overloaded Facility	Worst Contingency(ies)	Category	Loading (%) 2014	Loading (%) 2019	
CVLY-T-087	Stocton A-Weber #1 60 kV	N/A	A	<100%	103%	Reconductor
		Stockton A-Weber #2 60 kV and Stockton Wastewater #1	B	107%	113%	
		Stockton A-Weber #2 60 kV	B	105%	112%	
		Stockton A-Weber #2 60 kV and Stockton A-Weber #3 60 kV	C3	132%	140%	
		Stockton A-Weber #2 60 kV and Stockton A-Weber #3 60 kV	C3	118%	124%	

(*http://www.caiso.com/242a/242ae4765f2d0.pdf, Page 27, September 2009*)
(*http://www.caiso.com/2738/2738128a83260.pdf, Page 96, February 2010*)

b. Proposed Plan Solution:

The 2010 California ISO Transmission Plan (February 2010) states:

> "The most feasible implementation timeline for this upgrade due to permitting and lead time is 2011. In the interim load shedding will be used for both category B and C conditions.
> In response to this proposal the ISO has received the Stockton "A"-Weber #1 & #2 60 kV line Reconductor project from PG&E with operating date May 1, 2011. The ISO recommends approval for this project.
> It has demonstrated that the preferred alternative is a prudent and technically sound solution to the identified reliability concerns. The reconductoring of portions of these two lines plus the rerate of the Stockton "A"-Weber #3 60 kV line is the most cost effective mitigation to the possible reliability concerns in the area."
> (http://www.caiso.com/2738/2738128a83260.pdf, Page 117)

c. Proposed Plan Solution Cost:

Unknown. The cost of the CAISO proposed solution is not included in the 2010 California ISO Transmission Plan (*February 2010*)

d. Plan Timeframe: 2010

e. Proposed WGD Solution:

Staged installation of 14MW-55MW battery storage devices at Stockton A. Begin with 14MW in 2014, then grow to 55MW as load in the area increases.

f. WGD Solution Cost:

Initial Capital cost is $21M for 2014. The NPV for the project is $136 million.

g. CAISO Draft Response:

The Plan rejected the WGD Project based upon the following[21]:

- WGD has no obligation to build, own and maintain reliability-driven projects
- addresses the same reliability needs as the preferred alternative
- Much higher cost

(*http://www.caiso.com/2738/2738128a83260.pdf*, page 125)

h. WGD Comments and Questions:

The Plan acknowledges that the proposed WGD solution solves the same reliability needs as a reconductor project, but the Plan offers no supporting evidence or economic data to support the Plan's claim that the reconductor is a cheaper alternative. It is WGD's understanding that it will have significantly lower O&M and A&G costs than PG&E. Any economic analysis that was performed by the Plan should be transparent to determine if correct numbers were used during calculations. WGD believes that its overall project NPV will be significantly less (approximately $70.9 million) than a reconductor project performed by PG&E. WGD also believes that the Plan fails to provide substantial record evidence that such reconductoring can be completed by 2011 to address the subject reliability concern. Moreover, the WGD solution is also superior because it would also solve another reliability violation level B associated with the loss of Weber 230/60kv Bank.[22]

[21] Plan, p. 96.
[22] *http://www.caiso.com/2738/2738128a83260.pdf*, Page 120.

Exhibit 4

Madison 115kV

a. Description of Problem:

The 2010 CAISO reliability assessment results (September 2009) and the 2010 California ISO Transmission Plan (*February 2010*) identified that the Madison-Vaca 115kV line will reach 100.1% of its normal rating by 2014. (CVLY-T-041).

ID	Overloaded Facility	Worst Contingency(ies)	Category	Loading (%) 2014	Loading (%) 2019	
CVLY-T-041	Madison-Vaca 115 kV	N/A	A	100.1%	105.4%	Reconductor

(*http://www.caiso.com/242a/242ae4765f2d0.pdf, Page 27, September 2009*)
(*http://www.caiso.com/2738/2738128a83260.pdf, Page 93, February 2010*)

b. Proposed Plan Solution:

The 2010 California ISO Transmission Plan (February 2010) states:

> "Rerate is the preferred alternative. If rerate fails reconductoring this radial line could be a solution. The most feasible implementation timeline for this upgrade is 2014 due to permitting and lead times. This plan will be assessed further and included in the next annual ISO transmission plan.
> In response to this proposal the ISO has received the Madison-Vaca Dixon 115 kV line rerate project from PG&E with operating date May 1, 2014. The ISO recommends that PG&E pursue this alternative as soon as possible. Equipment rerates do not need ISO approval." (http://www.caiso.com/2738/2738128a83260.pdf, Page 116)

c. Proposed Plan Solution Cost:

Unknown. The cost of the CAISO proposed solution is not included in the 2010 California ISO Transmission Plan (*February 2010*)

d. Plan Timeframe: 2014

e. Proposed WGD Solution:

Install a 3MW-22MW battery storage device at PUTH CRK 115kV substation. Begin with 3MW in 2014, and grow to 22MW as load in the area increases

f. WGD Solution Cost:

Initial Capital cost is $4.5M for 2014. The NPV for the project is $70.2M (This includes taxes, O&M, A&G, etc).

g. CAISO Draft Response

The Plan rejected the WGD Project based upon the following[23]:

- WGD has no obligation to build, own and maintain reliability-driven projects
- addresses the same reliability needs as the preferred alternative
- re-rated the line

(*http://www.caiso.com/2738/2738128a83260.pdf, page 125-126*)

h. WGD Comments and Questions:

The Plan is recommending a re-rate of the overloaded facilities. This is a short-term solution which will become obsolete as load in the area continues to grow. This short term re-rate will eventually require a project similar to what WGD is proposing. It is significant that the Plan did not determine how long this short-tem re-rate will last, nor whether the WGD long term solution be implemented at that time. Furthermore, the Plan does not take into account an alternative that results in lower stranded cost. For instance, reconductoring may double the capacity of the line, but it will take over 20 years to utilize the capacity of the new line. WGD believe that a more cost effective and practical solution is to incrementally add capacity as needed by the load growth, rather than implement a reconductoring project that give much more capacity than is needed.

[23] Plan, pp 125-126.

EXHIBIT 5

Auburn 60kV

a. Description of Problem:

The 2010 CAISO reliability assessment results (September 2009) and the 2010 California ISO Transmission Plan (February 2010) identified that the Placer 115/60kV transformer #1 will reach its capacity by 2014 (Category A). (CVLY-T-005).

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading %		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
CVLY-T-005	Placer 115/60 kV	N/A	A	Normal	93%	106%	2017	Upgrade Atlantic-Placer corridor to 115 kV operation

(http://www.caiso.com/242a/242ae4765f2d0.pdf, Page 23, September 2009)
(http://www.caiso.com/2738/2738128a83260.pdf, Page 93, February 2010)

b. Proposed Plan Solution:

The 2010 California ISO Transmission Plan (*February 2010*) indicates that the proposed alternative would be to upgrade the Atlantic-Placer corridor to 115 kV operations:

> "Under normal conditions, the Placer 115/60 kV transformer could overload starting in year 2017. Also, under normal conditions, low voltages could appear in the area starting in year 2018. There are two potential overloads for category B single outage conditions starting in 2016. There are also multiple existing potential overloads, as well as low voltage and voltage deviations for category C conditions that can be mitigated by upgrading the Atlantic-Rocklin-Del Mar-Penryn-Placer system to 115 kV operation. This would be achieved by upgrading the existing Atlantic-Del Mar #1 and #2 60 kV to 115 kV operations, as well as rebuilding Placer-Del Mar to a 115 kV DCTL and having the entire system looped through. The most feasible implementation timeline for this upgrade is 2016 due to permitting and lead times. In the interim, load shedding will be used for most category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan." (http://www.caiso.com/2738/2738128a83260.pdf, Page 116)

c. Proposed Plan Solution Cost:

PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) indicates that the Atlantic-Placer Voltage Conversion project is expected to cost between $50M and $60M; however it is unclear if the PG&E cost estimate includes the rebuilding of the Placer-Del Mar to a 115kV DCTL (2009 Electric Transmission Grid Expansion Plan, Section 6, Page 85). If this cost estimate does not include the rebuild of the Placer-Del Mar 115kV line, than the project cost would be even higher than stated.

d. Plan Timeframe: 2014

e. Proposed WGD Solution:

WGD is proposing a 29MW battery storage device at the Auburn 60kV substation.

f. WGD Solution Cost:

Initial Capital cost is $43.5M. The NPV for the project is $233.4M (This includes taxes, O&M, A&G, etc).

g. CAISO Draft Response:

The Plan rejected the WGD Project based upon the following:

- WGD has no obligation to build, own and maintain reliability-driven projects
- not clear that this project can charge enough in order to help mitigate the binding constraints in the area
- only addresses a small part of the needs in the Placer area
- Atlantic-Placer voltage upgrade along with other alternatives will be assessed further in next ISO transmission plan

(*http://www.caiso.com/2738/2738128a83260.pdf*, page 126)

h. WGD Comments and Questions:

There appears to have been no effort made on the Plan's part to understand the proposal put forth by WGD, as evidenced by the Plan's statement that it was not clear that the battery could charge enough to help mitigate the binding constraint. WGD's application included detailed power flow analysis demonstrating that the proposed battery size would mitigate the system overload on a long term basis. The Plan is nonspecific in its statement that the WGD solution only addresses a small part of the needs in the Placer area; the Plan also provides no explanation of why WGD's proposal cannot fit into the overall Plan.

Potrero 115kV

a. Description of Problem:

The CAISO 2010 Local Capacity Technical Analysis Final Report and Study Results (May 2009) for the San Francisco Sub-area identified that Potrero 3 will be shut down when the TBC becomes operational. The LCR requirements for SF area will be 25MW in 2010, 15MW in 2011, and 10MW in 2013.

> **"San Francisco Sub-area**
> Once the Trans Bay DC cable is placed in service, the ISO estimates that, at minimum, 150 MW of San Francisco generation will be required in order to allow clearances, in off-peak conditions, for the remaining three re-cabling projects within San Francisco as well as clearances for the Newark-Ravenswood 230 kV reconductoring.
> The exact quantity can only be established once all clearance requests are received and processed. Tentative schedules are set for the beginning of 2011 and the end of 2010 respectively.
> After the Trans A-H-W #2 115 kV re-cabling project and the Bay DC cable are operational, the LCR needs (at peak) for San Francisco will be based on an outage of the Trans Bay DC cable and A-H-W* #1 115 kV cable. The area limitation is thermal overloading of the A-H-W* #2 115 kV cable (at the current projected rating). This limiting contingency establishes a LCR of 25 MW in 2010 (includes 0 MW of Muni generation)." (http://www.caiso.com/23a1/23a186dd41f50.pdf, Pages 51-52)

*Please note that the A-H-W lines are the Martin-Bayshore-Potrero 115kV lines.
The CAISO reiterates this overload in its September 15, 2009 posting for the Greater Bay Area Long-Term Study Results where they identify that loss of the TBC and the Martin-Potrero No. 1 115kV line (A-H-W #1) will cause the Martin-Bayshore No. 2 115kV line (A-H-W #2) to reach 1.02 (P.U.) by 2014. *(http://www.caiso.com/242a/242af118697c0.pdf, Page 11)*

b. Proposed Plan Solution:

Contradictory to the CAISO's September 15, 2009 posting, the CAISO states in the 2010 California ISO Transmission Plan (*February 2010*) that no generation is required:

> *"With a significant reduction in load forecast for San Francisco over the next ten years and planned completion of re-cabling of Martin-Bayshore-Potrero cables #1 and #2 by October 2010 it was determined that no generation at Potrero or additional transmission in San Francisco is needed."* (http://www.caiso.com/2738/2738128a83260.pdf, page 155)

c. Proposed WGD Solution:

ZGlobal concurs with the CAISO's LCR assessment and are proposing 20MW battery storage at Potrero 115kV substation to reduce LCR.

d. Proposed Plan Timeframe: unclear

e. <u>WGD Proposed Solution:</u> WGD concurs with the CAISO's LCR assessment and are proposing 20MW battery storage at Potrero 115kV substation to reduce LCR

f. <u>WGD Solution Cost:</u>

Initial Capital cost is $30M. The NPV for the project is $149.8M (This includes taxes, O&M, A&G, etc).

g. <u>CAISO Draft Response:</u>

The Plan rejected the WGD Project based upon the following:

- WGD has no obligation to build, own and maintain reliability-driven projects
- Significant reduction in load forecast for San Francisco over next 10 years
- Re-cabling the Martin-Bayshore-Potrero cables #1 and #2 (Oct 2010)
- Not needed

(*http://www.caiso.com/2738/2738128a83260.pdf, page 155*)

h. <u>WGD Comments and Questions:</u>

In contrast to the September 15, 2009 posting, the Plan concludes, without providing adequate justification, that no generation is required: "With a significant reduction in load forecast for San Francisco over the next ten years and planned completion of re-cabling of Martin-Bayshore-Potrero cables #1 and #2 by October 2010 it was determined that no generation at Potrero or additional transmission in San Francisco is needed."[24] In addition, the Plan incorrectly states that the WGD energy storage device is not needed because the Martin-Bayshore-Potrero lines will be reconductored in October of 2010; however this is contradictory to multiple Plan studies that identify a need for generation <u>after</u> the reconductor project. Furthermore the Plan studies indicated the need for generation using a certain load forecast. The Plan now wants to arbitrarily lower the load forecast for WGD studies in an attempt to alleviate the Project's need. WGD has consistently argued, on multiple occasions including the 2010 LCR studies and as recently as the September 15th posting, that it is inappropriate to change load level assumption used by the Plan.

[24] Plan, p 155.

Exhibit 7

Guernsey 70kV

a. Description of Problem:

The 2010 CAISO reliability assessment results (September 2009) and the 2010 California ISO Transmission Plan (*February 2010*) identified of the Corcoran 115kV/70kV bank will reach 105% of its normal rating by 2014 (FRES-SP-T-016).

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%) 2014	Loading (%) 2019	Exp. Yr. of Occurrence	ISO Proposed Solution
FRES-SP-T-016	Bank between Corcoran 115 kV To Corcoran 70 kV Ckt #2	N/A	A	Normal	105%	110%	2010	replace transformer with higher capacity

(*http://www.caiso.com/242a/242ae4765f2d0.pdf, Page 39, September 2009*)
(*http://www.caiso.com/2738/2738128a83260.pdf, Page 160, February 2010*)

In addition to the CAISO identified overload, PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) lists an additional reliability concern in the area. In the expansion plan PG&E states the Corcoran-Guernsey 70kV line is normally open. In an outage of the Guernsey-Henrietta 70kV line, the Corcoran-Guernsey 70kV line can be closed to pick up the lost load; however the Corcoran source cannot support both Guernsey and Corcoran load. (*2009 Electric Transmission Grid Expansion Plan, Section 6, Page 108*)

b. Proposed Plan Solution:

The 2010 CAISO reliability assessment results (September 2009) and the 2010 California ISO Transmission Plan (*February 2010*) list that adding a second transformer bank is the CAISO proposed alternative.

The 2010 California ISO Transmission Plan (February 2010) states:

> *"The Corcoran 115 kV To Corcoran 70 kV transformer bank #2 was identified as overloaded under NERC Category A conditions in the 2014 and 2019 summer peak case to 105% and 110%, The mitigation plan is to replace the transformer with a higher capacity transformer as soon as practicable. This project was proposed through the request window and is being recommended for approval in the 2010 ISO TP."* (*http://www.caiso.com/2738/2738128a83260.pdf, Page 174*)

PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) has additional plans for the area. PG&E is proposing a conversion of the Guernsey 70kv substation to 115kV, a new 115kV transmission line from Guernsey to GWF switching station, and a conversion of the Corcoran-Guernsey 70kV line to 115kV operation. (*2009 Electric Transmission Grid Expansion Plan, Section 6, Page 108*)

c. Proposed Plan Solution Cost:

PG&E's Guernsey 70kV to 115kV conversion project is estimated by PG&E to cost between $10M and $15M. This project does not include the cost of replacing the transformer bank. The cost of the CAISO proposed Corcoran 115/70kV bank #2 is not included in the 2010 California ISO Transmission Plan (*February 2010*); therefore the total project cost is unknown.

d. Plan Timeframe: 2014

e. Proposed WGD Solution:

Install a 7MW-14MW battery storage at Corcoran or Guernsey 70kV substations

f. WGD Solution Cost:

Initial Capital cost is $10.5M for 2010. The NPV for the project is $71.9M (This includes taxes, O&M, A&G, etc).

g. CAISO Draft Response:

The Plan rejected the WGD Project based upon the following:

- WGD has no obligation to build, own and maintain reliability-driven projects
- Cost for Corcoran Transformer is less
- Corcoran Transformer design is simpler
- Failed to take into account Henrietta SPS
- Will cause voltage collapse when the Henrietta SPS was triggered
- Redesign of the SPS is not within the ISO guidelines for SPS design
- Battery charging during off-peak period will adversely impact Helms Pumping

(*http://www.caiso.com/2738/2738128a83260.pdf, page 181*)

h. WGD Comments and Questions:

The Plan's response to WGD's Guernsey project demonstrates the Plan's apparent inability to give fair and reasonable consideration to new and innovative solutions. The Plan's statement that the Corcoran bank is a simpler solution is proof of this fact. WGD would argue that the Plan should be giving consideration to all projects in order to find the lowest cost alternative for ratepayers. The Plan lists no supporting evidence or economic data to support the claim that the new Corcoran Bank is a cheaper alternative. Furthermore, the Plan states that the battery's charging cycle will somehow directly affect Helms Pumping schedule. It is erroneous for the Plan to make such assertions without providing studies, if any, to support this statement, particularly because Guernsey is on a small pocket of PG&E's 70kV system, and Helms is connected to the larger more interconnected 230kV system. WGD would like to understand the Henrietta SPS better to find out if the issues surrounding the SPS can be resolved.

<u>EXHIBIT 8</u>

Coppermine 70kV

a. <u>Description of Problem:</u>

PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) expansion plan identified that for summer peak conditions an outage of the Borden-Coppermine 70kV when Friant generation is offline, will cause low voltages in the Coppermine 70kV area. (2009 Electric Transmission Grid Expansion Plan, Section 6, Page 101)
The CAISO supported PG&E's assessment, and in the Final 2009 CAISO Transmission Plan (June 2009) the CAISO listed that an outage of the Friant Gen combined with an outage of the Borden-Coppermine (listed as Category B), would overload the Coppermine-Reedley 70kV to 119% of its emergency rating by 2013, and 138% by 2018.

Limiting Element **Outage** **Category** **2013** **2018**
Recommendation

Coppermine - Reedley 70kV Line	Borden - Coppermine 70kV Line + Friant gen	B	119%	138%	Reconductor Coppermine - Reedley 70kV Line or De-Loop the 70kV System

(*<u>http://www.caiso.com/1ca5/1ca5d8334b920.html</u>, Page 137*)

The CAISO further eluted to problems in the Borden 70kV system in the 2010 California ISO Transmission Plan (*February 2010*). The CAISO listed two outages, that in combination with Friant Dam being offline, created overloads on the Borden-Coppermine 70kV line. In the table below the CAISO listed the overload on the Borden-Cassidy 70kV line and this is a portion of the Borden-Coppermine 70kV line.

Limiting Element **Outage** **Category** **2014** **2019**
Recommendation

FRES-SP-T-091	Line between Borden 70 kV To Cassidy 70 kV Ckt #1	Mc Call - Wahtoke 115 kV #1 and Frantdm GSU	C	L-1/T-1	<100%	105%	2015	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-092	Line between Borden 70 kV To Cassidy 70 kV Ckt #1	Frantdm GSU and Tvy Vlly - Reedley 70 kV #1	C	L-1/T-1	<100%	107%	2015	Establish 15 minute rating, curtail load within 15 minutes

(*<u>http://www.caiso.com/2738/2738128a83260.pdf</u>, Page 164*)

b. <u>Proposed Plan Solution:</u>

PG&E is proposing a conversion of the Borden-Coppermine 70kV system to 115kV, a new source from Herndon Substation, a new Coppermine 115/70kV bank, and new Herndon-Coppermine 115kV line. (2009 Electric Transmission Grid Expansion Plan, Section 6, Page 101) The 2009 CAISO Transmission Plan (June 2009) recommends a Reconductor of the Coppermine-Reedley 70kV or a De-Loop of the 70kV system. The 2010 CAISO Transmission Plan (*February 2010*) recommends establishing a 15 minute rating followed by load dropping post contingency.

c. <u>Proposed Plan Solution Cost:</u>

WAS:158942.1

PG&E's proposed solution is estimated by PG&E to have a capital cost between $25-40M, this cost does not include O&M, A&G, etc. The cost of the CAISO proposed recommendations are not included in the 2009 or the 2010 California ISO Transmission Plan; therefore these project costs are unknown.

d. Plan Timeframe: 2014

e. Proposed WGD Solution:

Install 10MW-45MW battery Storage at Coppermine 70kV substation. Begin with 10MW in 2010, and then grow to 45MW as the load in the area increases.

f. WGD Solution Cost:

Initial Capital cost is $15M for 2014. The NPV for the project is $164.3M (This includes taxes, O&M, A&G, etc).

g. CAISO Draft Response:

The Plan rejected the WGD Project based upon the following:

- WGD has no obligation to build, own and maintain reliability-driven projects
- Analysis was flawed
- Analysis assumed three generating units were forced out of service
- Category D

(http://www.caiso.com/2738/2738128a83260.pdf, page 181)

h. WGD Comments and Questions:

In June of 2009, the CAISO Final 2009 Transmission plan was released which stated that the outage of the Borden-Coppermine 70kV line plus Friant Gen was a Category B outage to which the Plan recommended a reconductor project. When WGD listed this outage combination in its application, the Plan's response was that the analysis was flawed and that this contingency pair should be considered a Category D contingency. The Plan does not explain why WGD's findings for this outage pair are being overlooked when the Plan stated that it recommended a reconductor project for this specific contingency pair. Furthermore, an outage of the Friant Dam's generator step up transformer combined with the Borden-Coppermine 70kV would at the worst be a Category contingency. This once again displays the dismissive and flawed review of WGD's projects in the Plan.

EXHIBIT 9

Weedpatch 70kV

a. Description of Problem:

The 2010 CAISO reliability assessment results (September 2009) identified that loss of the Wheeler-Weedpatch while Kern Canyon Generation is offline will place the line segment from San Bernard to Stalin Jct 70kV at 100% of its emergency rating by 2014 (KERN-SP-T-049).

ID	Overloaded Facility Name	Worst Contingency(ies)	Category	Loading (%) 2014	Loading (%) 2019	ISO Proposed
KERN-SP-T-049	Line between Sn Brnrd 70 kV To Stalons 70 kV Ckt #1	wheeler-weedpatch 70 and kerncnyn g-1	B	100%	101%	Re-rate or reconductor

.(*http://www.caiso.com/242a/242ae4765f2d0.pdf, Page 46, September 2009)*

b. Proposed Plan Solution:

The CAISO recommended in the 2010 CAISO reliability assessment results (September 2009) a re-rate or Reconductor of the lines. (*http://www.caiso.com/242a/242ae4765f2d0.pdf, Page 46, September 2009)*

c. Proposed Plan Solution Cost:

Unknown. The cost of the CAISO proposed solution is not included in the 2010 California ISO Transmission Plan (*February 2010*)

d. Plan Timeframe: 2014

e. Proposed WGD Solution:

Install 3MW-18MW battery storage at Weedpatch 70kV. Begin with 3MW in 2014, and then grow to 18MW as load in the area increases.

f. WGD Solution Cost:

Initial Capital cost is $4.5M for 2014. The NPV for the project is $60.4M (This includes taxes, O&M, A&G, etc).

g. CAISO Draft Response:

The Plan rejected the WGD Project based upon the following:

- WGD has no obligation to build, own and maintain reliability-driven projects
- PG&E implemented a operating procedure to Normally Open Weedpatch CB 42
- Not needed

(*http://www.caiso.com/2738/2738128a83260.pdf, page 181*)

h. WGD Comments and Questions:

In the past, the CAISO has supported some extravagant projects proposed by utilities that involved looping transmission systems to increase system reliability. The Plan originally recommended a reconductor project for this area, but the Plan is now suggesting that the utility de-loop the transmission system and therefore decrease system reliability. The Plan appears to be so interested in excluding third parties proposals that the Plan proposes to reduce system reliability by de-looping the transmission system, before allowing third party transmission to be built.

ATTACHMENT S

California ISO
Your Link to Power

California Independent System Operator Corporation

Via Federal Express

May 5, 2010

Mr. Roger D. Feldman, Esq.
Andrews Kurth, LLP
1350 I Street NW, Suite 1100
Washington, DC 20005

RE: Western Grid Development, L.L.C.
Request Window Submissions

Dear Mr. Feldman:

In a letter dated March 2, 2010, you expressed your disagreement with the California Independent System Operator Corporation's (ISO) decision to reject eight proposed reliability network upgrades submitted by Western Grid Development, LLC (WGD). You allege that the reasons for rejecting the WGD projects are (1) technically flawed, (2) not supported by sufficient evidence, and (3) arbitrary and capricious and inconsistent with Order No. 890. As discussed in greater detail below, the ISO respectfully disagrees with the statements and conclusions in your letter.

WGD's General Allegations Lack Merit

As an initial matter, your letter paints an inaccurate picture of how the ISO's transmission planning process works. You state that reliability projects identified by third parties do not have an opportunity to compete on an equal footing with reliability projects identified by Participating Transmission Owners (PTOs) and claim that the right of first refusal for PTOs to build reliability projects could result in ratepayers paying for PTO projects that are technically inferior, more expensive and take longer to complete than alternatives submitted by non-PTOs. These statements are incorrect. The purpose of the ISO's assessment of reliability projects is to identify the transmission upgrade or addition that best meets the ISO's reliability needs in a cost-effective manner. That upgrade or addition can be a project proposed by the PTO, a project proposed by a third-party, or an alternative proposed by the ISO during the transmission planning process. The ISO tariff does not require the ISO to approve the reliability project proposed by the PTO if it is not the best solution. Thus, under the ISO's transmission planning process, ratepayers are not required to pay for PTO projects that are technically inferior to and not as cost effective as non-PTO proposed projects. The ISO evaluated WGD's proposed projects and found that they were not the best solutions for the reliability needs identified by the ISO.

In the letter you state that it is arbitrary for the Transmission Plan to reject WGD's reliability solutions because WGD is not a PTO. You claim that it is premature to exclude WGD from building reliability projects because WGD has not yet applied for PTO status and argue that this is a chicken and egg rationale that would preclude new PTOs from ever building reliability projects. Contrary to your claims, the ISO did not reject WGD's proposed solutions because WGD is not a PTO. The ISO rejected WGD's proposed solutions because the ISO found that (1) there is no reliability need for any transmission project in three of the areas where WGD submitted projects, and (2) other specific projects proposed by WGD were not the best solution to meet the identified reliability needs based on the ISO's evaluation of the relative merits of competing projects. In other words, even if the battery storage projects had been proposed by Pacific Gas & Electric Company, the ISO would have denied them. Your argument also reflects a fundamental misunderstanding of the ISO tariff. Merely being a PTO does not convey a right to build reliability projects. Under Section 24.1.2 of the tariff, with respect to reliability projects"[t]he Participating TO with a PTO Service Territory in which the transmission upgrade or addition deemed necessary ... is to be located shall be the Project Sponsor, with the responsibility to construct, own, finance and maintain such transmission upgrade or addition." A PTO Service Territory is defined as "[t]he area in which an IOU, a Local Public Owned Electric Utility or federal power marketing authority has turned over its transmission facilities and/or Entitlements to CAISO Operational Control is obligated to provide electric service to Load. Because WGD does not have a PTO Service Territory, it does not have the right to build reliability projects under Section 24.1.2 even if it were a PTO.

Your letter states that seven of the eight WGD projects are significantly cheaper than the PG&E alternatives. You also, make the unsubstantiated claim that approval of the WGD projects would save ratepayers over $100 million and, if WGD were to construct and operate the projects, the savings to consumers would exceed $522 million (purportedly because WGD's operation and maintenance and administrative and general costs are lower than PG&E's). These claims are based on incorrect facts, a deeply flawed cost comparison analysis, and significantly understated costs for several of WGD's projects.

First, the capital costs of two of the PG&E alternatives, namely Stockton and Madison are exponentially lower than the competing WGD projects.

Second, your letter ignores the fact there is no need for any reliability project in three-of-the-eight areas, namely Potrero, Weedpatch and Coppermine. Accordingly, even accepting WGD's flawed cost comparison analysis, the purported overall cost savings alleged by WGD is inflated.

Third, WGD has significantly understated the costs associated with several of its projects. With respect to Tulucay, you ignore the fact that the ISO Board has previously approved a reliability project that addresses all of the reliability needs in the area; whereas, the

WGD project only addresses one of the two identified reliability needs. Thus, your cost comparison analysis fails to account for the additional costs that would be required to solve the reliability need that the battery does not solve. Your cost comparison for Guernsey ignores the fact that if the ISO were to approve the project proposed by WGD, two new Special Protection Schemes would need to be installed at significant additional cost. WGD's analysis does not reflect these costs. Also, your Guernsey cost analysis ignores the fact that the ISO- approved project replaces a transformer that went into service in 1931 and is slated to be replaced in 2013. Your cost analysis fails to include the additional costs that would be incurred to replace the transformer if the ISO were to approve the battery storage project, rather than the transformer replacement project. The Auburn cost comparison is not an "apples-to-apples" comparison because the PG&E project resolves significantly more reliability needs that the WGD project. Thus, your analysis fails to account for the additional costs that would be needed to meet these unresolved needs if the ISO were to approve the WGD projects. Under these circumstances, WGD's projects do not constitute cost effective solutions to resolve identified reliability needs. When these additional costs are taken into consideration, the capital costs of the PG&E projects are clearly less than the costs of WGD's projects.

Fourth, there are significant flaws with the cost comparison analysis that you have provided. As an initial matter, WGD has not provided a detailed accounting of its purported O&M and A&G costs.. Thus, there is no basis to assess the reasonableness of such costs and determine whether they capture all of the costs likely to be incurred in connection with the operation of WGD's proposed projects. In any event, the ISO is in no position, within its transmission planning process to be determining what O&M and A&G costs will result from, and be allocated to, a particular transmission project over the life of that project. O&M and A&G costs levels, and the allocation of such costs are issues typically handled in a rate case proceeding before a regulatory agency. It is entirely speculative what a company's O&M and A&G costs will be for the next 30 years and what levels of such costs will be allocated/assigned to specific projects during that timeframe. There are a myriad of variables that affect the level of a company's O&M and A&G costs from rate case to rate case, and WGD's analysis does not account for any of them. For example, WGD could sell its transmission facilities to a third-party that has higher O&M and A&G costs. This scenario, which has already occurred within the ISO footprint and which could increase the costs of WGD's project, would not be captured in the need analysis, and could result in an erroneous decision to approve a project that turns out to be the higher cost project. Also, your cost analysis appears inappropriately to allocate a full share of O&M and A&G costs based on PG&E's existing system to each of PG&E's proposed projects. The O&M and A&G for PG&E's entire existing system (which includes an extensive quantity of aged facilities that require increased maintenance) is not representative of the O&M and A&G associated with the new facilities that PG&E is proposing to build. Even assuming *arguendo* that it was appropriate for the ISO to consider O&M and A&G costs, only the incremental O&M and A&G costs, if any, that result from the construction of these projects should be considered. However, determining such costs would be entirely speculative at this point in time. Indeed, these projects may actually cause a decrease in PG&E's O&M costs because the reconductoring of existing lines and the replacement of old equipment will result in reduced maintenance costs compared to the maintenance costs associated with the facilities they are replacing. Also, you ignore the fact that PG&E's A&G costs are allocated based on labor ratios, not transmission plant. Thus, there is no basis to claim that A&G costs would increase as a result of approving PG&E's projects. Further, because there is no reliability need for three of WGD's proposed projects and two of the WGD projects have a exponentially higher costs than the competing PG&E projects, WGD's overhead and fixed O&M/A&G costs would have to be allocated over a smaller number of remaining projects, thus driving up the costs of those projects.

The ISO's response to your specific comments regarding the ISO's treatment of the individual projects submitted by WGD is set forth in Exhibit 1. For the reasons set forth herein, the ISO believes that it has approved technically superior and cost effective solutions to meet identified reliability needs, and its decisions regarding the treatment of WGD's request window submissions are fully supportable.

Respectfully submitted,

Gary DeShazo
Director
Regional Transmission (North)

cc: *via email*

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EXHIBIT 1

Borden-Coppermine

The letter claims that the ISO failed to show how the Borden-Coppermine 70kV was transformed from a Category B concern in the 2009 Transmission Plan to a Category D in the 2010 Plan. The Category B low voltage problem and overloads identified by PG&E and the ISO in the 2009 plan were resolved by a previously completed maintenance project, the Coppermine-Tivy Valley-Reedley 70 kV reconductoring project. This project was completed on September 30, 2008. The Coppermine-Tivy Valley-Reedley 70 kV reconductoring project was not modeled in the analysis for the final 2009 transmission plan. In that regard, – base cases for the 2009 analysis were developed in April 2008,*i.e.,* before the maintenance project was completed However, the ISO modeled this project in the analysis for the 2010 transmission planning process, and the ISO found no reliability problem. Accordingly, there is no need for any new reliability project in this area.

Tulucay

Your claim that there have been reliability problems in the Tulucay area for more than three years and that no remedial project has been submitted to the ISO is incorrect. In April 2006, the ISO Board approved a project to reconductor the Vaca-Dixon –Tulucay and Vaca Dixon- Lakeville 230 kV lines. This project will resolve all of the previously identified reliability needs in the area on a long-term basis. WGD's Tulucay storage project is functionally duplicative of a previously approved transmission project. In any event, the ISO addresses your specific arguments regarding this project below.

Your claim that the ISO's preferred approach is to drop load and open-up two lines is incorrect. The ISO's preferred long-term approach is to construct the reconductoring project previously approved by the Board. In the interim, sufficient in-area generation has been procured each year to ensure that overloads will not occur on the lines. In addition, PG&E has an operating procedure to open the parallel line (open Vaca Dixon – Lakeville following the outage of Vaca Dixon – Tulucay and vice versa), which can be used to prevent overloads on the two lines. The procurement of sufficient local capacity and the operating procedure are essentially *interim* solutions until the Board-approved project to reconductor the Vaca Dixon – Tulucay and Vaca Dixon – Lakeville 230 kV lines is completed. Because local capacity is procured only for one year in the future, it is not realistic to assume the availability of a sufficient level of local capacity in the reliability assessment assumptions on a long-term basis. That is why the ISO's long-term assessment still shows potential overloads on these two transmission facilities. In any event, your claim that use of the operating procedure is the preferred long-term solution is incorrect; it is only an interim solution. Load dropping is permissible for Category C contingencies such as these.

WGD has proposed a project that addresses a reliability need for which the ISO has already approved a transmission project to address. The Board-approved project resolves overload concerns on both lines in the area; whereas, the WGD's project proposed only resolves overloads on one line. You state that the ISO failed to show how the battery only relieves the overload on one bottleneck and not both.

In assessing why the battery storage project is not the better solution for addressing the reliability concerns in the Tulucay area, it is important to understand system configuration in this area. Please note that all the figures below were created to show the overall impact from the storage project under various system conditions. Figure 1 provides an overview of network topology between Vaca Dixon and Lakeville substation. As shown in figure 1, Vaca Dixon – Lakeville is shown as a single line between Vaca Dixon and Lakeville substations. The Vaca Dixon – Tulucay consists of 2 sections. First is a 230 kV line between Vaca Dixon – Tulucay and the second [d] section is a 230 kV line between Tulucay – Lakeville 230 kV substations.

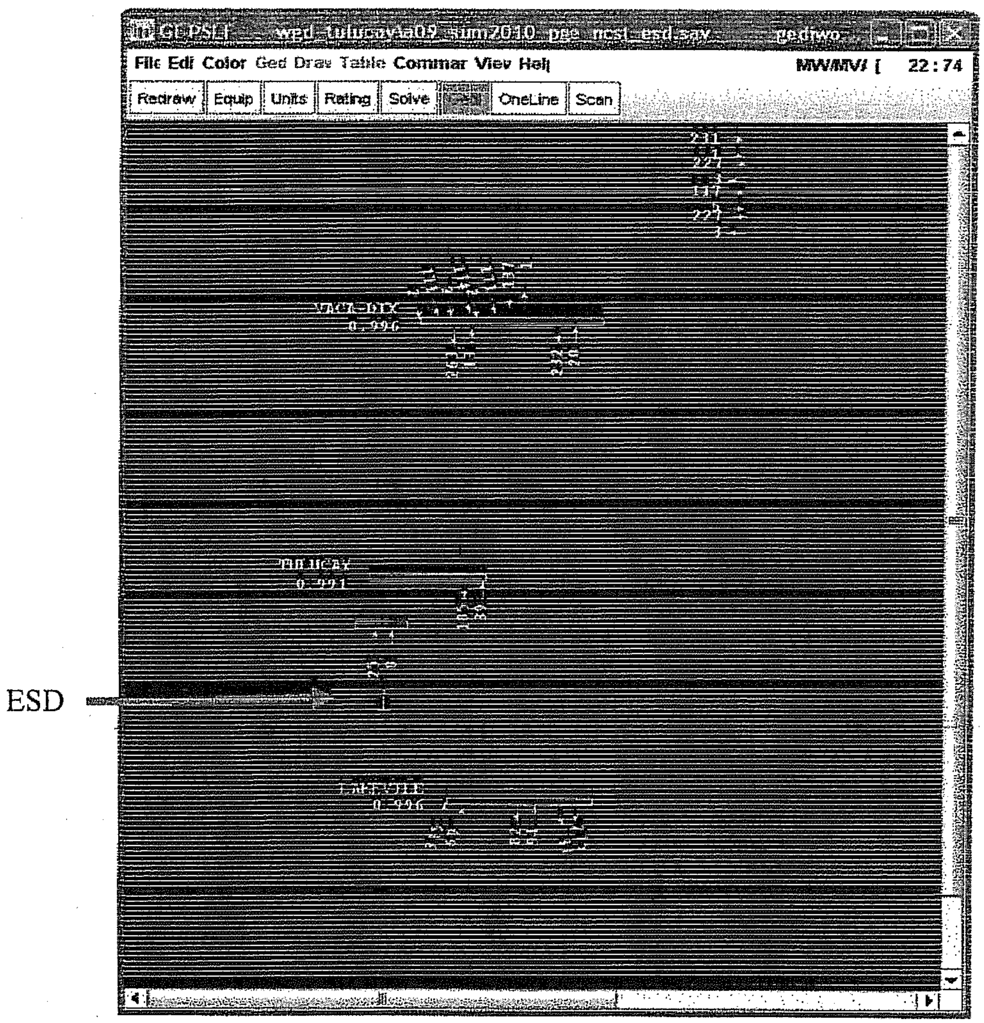

Figure 1: Network topology showing the Tulucay battery project and neighboring area

As shown in figure 2, during the outages of Vaca Dixon – Lakeville and Lakeville – Geysers 9 (shown as dotted line), the section of transmission lines between Vaca Dixon and Tulucay substations can be overloaded. .The battery storage project can reduce power flow on this section(from Vaca Dixon – Tulucay substation) under this condition.

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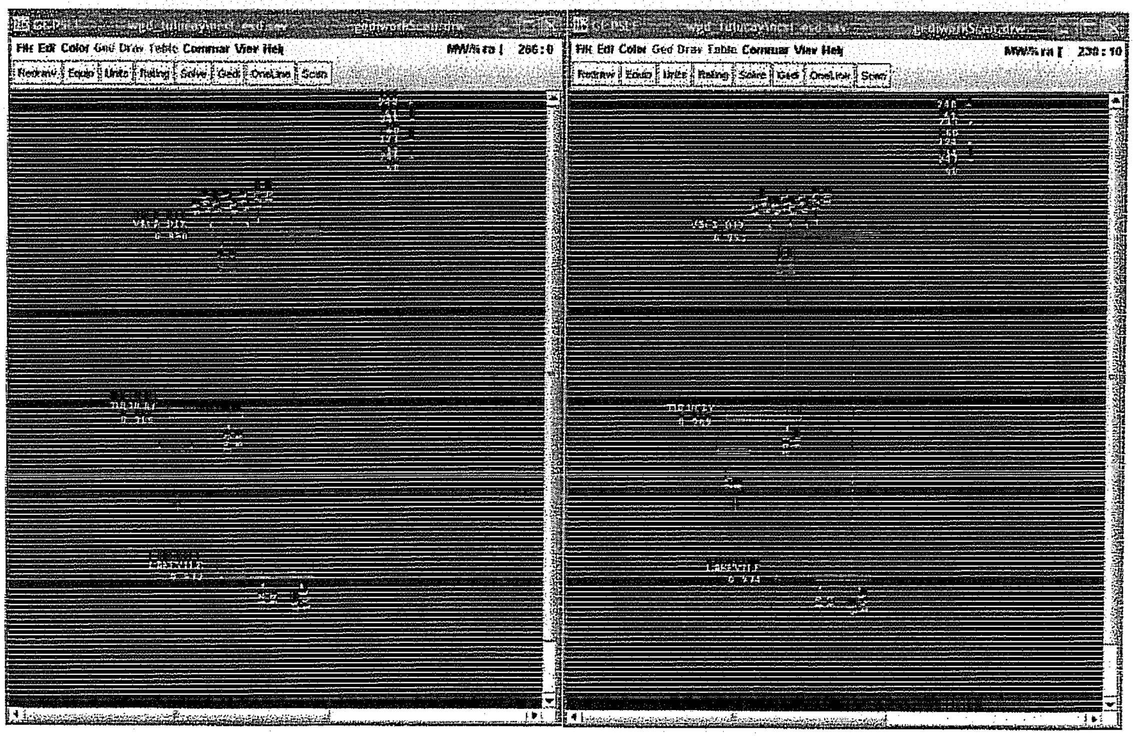
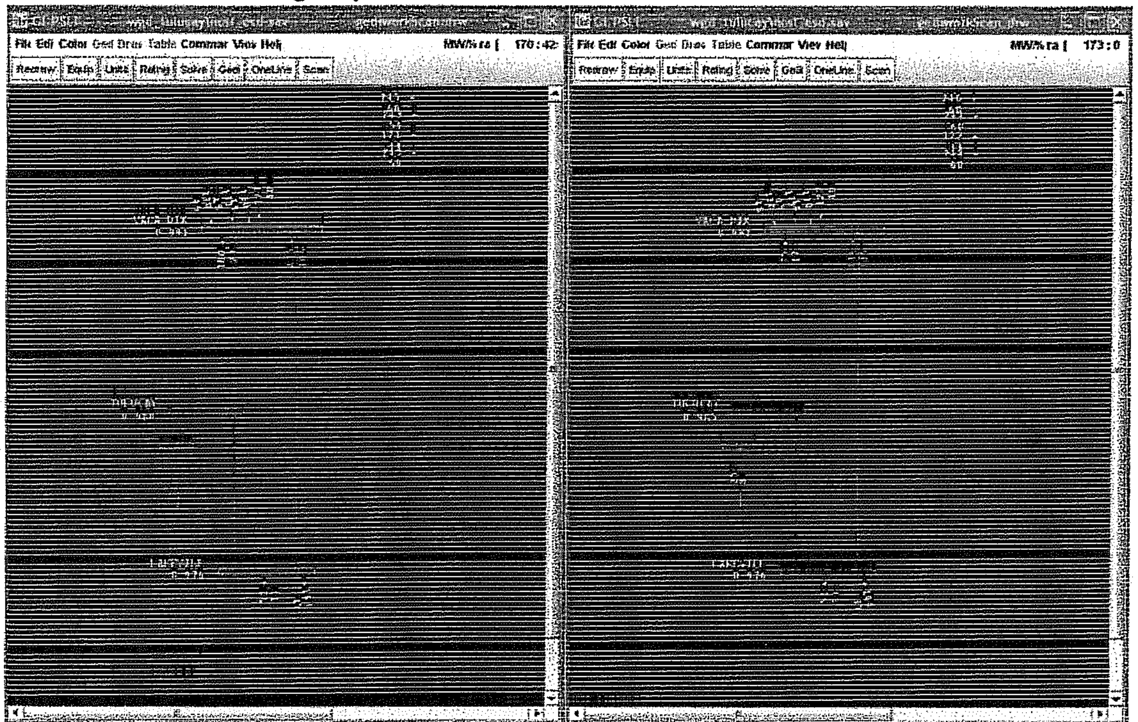


ESD Off ESD on

Figure 2: Impact on power flow on Tulucay – Vaca Dixon line from ESD project following the outages of loss of Vaca Dixon – Lakeville and Lakeville – Geysers 9

However, while the battery project can reduce power flow from Vaca Dixon to Tulucay under the contingency conditions shown in figure 2, the ISO study results show that this is not the only contingency that can cause overloads in the area. The transmission line between Vaca Dixon – Lakeville can also be overloaded under various contingencies such as outages of Tulucay – Lakeville and Lakeville – Geysers 9. As shown in dotted lines in figure 3, under these contingencies (Tulucay – Lakeville and Lakeville – Geysers 9), the battery project does not reduce the flow on the limiting facility (Vaca Dixon – Lakeville). In other words, the battery storage unit does not resolve the overload under this contingency. To the contrary, it may in fact exacerbate potential overloads on the Vaca Dixon – Lakeville 230 kV line under the contingency (by increasing power flow from the already overloaded line from 435 MW to 436 MW). Although this is not a major increase in the power flow, more local capacity in the North Coast and North Bay may be required to back off this additional flow when the battery is in service if this limitation is the most critical contingency.



ESD Off ESD on

Figure 3: Impact on power flow on Tulucay – Vaca Dixon line from ESD project following the outages of loss of Lakeville – Tulucay and Lakeville – Geysers 9

The above comparison shows that the battery storage device may be used to mitigate overload on the Vaca Dixon – Tulucay line. However, for potential overloads on Vaca Dixon – Lakeville 230 line under contingency conditions shown in figure 3, installation of the battery does not reduce potential overload caused by power flow from Vaca Dixon to Lakeville. On the other hand, the Board-approved reconductoring project solves both problems because both the Vaca Dixon – Tulucay and Vaca Dixon – Lakeville 230 kV will be reconductored with larger conductor.

Your claim that the battery storage solution is a cheaper solution is based on a flawed cost analysis, as discussed above, and fails to recognize that the battery only solves one of the reliability needs, *i.e.*, it does not take into account the additional costs that would be incurred to resolve the remaining reliability problem on the Vaca-Dixon-Lakeville line.

Madison

With respect to WGD's Madison project, your letter argues that the ISO offered no evidence that the re-rating of the line is a superior solution to the battery storage facility. You also claim that the cost of WGD's solution is "significantly lower". Finally, you contend that re-rating the line is technically flawed because the plan concluded that this line would exceed 100% of its existing rating, thereby requiring relief.

Your arguments are wholly without merit. The cost of the rerate is minimal, usually less than $100,000 for a facility like this. On the other hand, WGD estimated the initial capital cost of the battery to be $4.5 million, with additional capital costs to be incurred as the capabilities of the battery increase from 3 MW to 22 MW. Thus, the cost of a re-rate is significantly lower than the cost of the battery storage unit proposed by WGD. Moreover, the re-rating is expected increase the rating of the line by approximately 12-15%. The Vaca-Madison 115 kV line loading is increasing at a rate of about 1% per year. Thus, a successful rerate would mitigate the reliability need for approximately 12-15 years, moving the need for a transmission project to 2026-2029 timeframe. Rerating the line from a 2 feet/second wind speed to 4 feet/second wind speed, where possible, is technically feasible and has been implemented successfully at numerous locations across the ISO's footprint. Once a line is successfully rerated to a higher value, there is no overload as you claim. This approach clearly represents the most cost effective remedy.

Stockton

The letter notes that the ISO concluded that the PG&E reconductoring project was superior and lower cost compared to WGD's Stockton battery storage project, but failed to indicate the cost of PG&E's project. The Stockton "A"-Weber #1 & #2 60 kV line reconductor project with an operating date May 1, 2011 has a capital cost of $5-10 million. On the other hand, the initial cost of WGD's Stockton battery storage project is $21 million, with additional capital costs to be incurred as the battery storage capabilities increase from 14 MW to 55 MW as load in the area increases. WGD's cost comparison analysis is also flawed for the reasons discussed above.

Your claim that the reconductoring cannot be completed by May 2011 is likewise unsubstantiated. The entire line does not need to be reconductored, only parts of it do. Reconductoring small portions of existing lines only require a NOC (Notice of Construction) from the CPUC, and the process usually takes 3-6 months. The ISO has no basis to question the completion of the project by PG&E before June 1, 2011. Your argument is also disingenuous because, as reflected in WGD's request window submission, WGD proposed an in-service date of March 30, 2014 for the storage battery, long after the reconductoring project will have been completed.

Also, prior to your letter, WGD never mentioned that it was also proposing the Stockton battery to mitigate the Weber 230/60 kV Bank. Indeed, WGD's request window submission only states that the project is intended to address a potential overload on the Stockton A-Weber 60kV line. In any event, the ISO compared this alternative with the bank replacement and determined that, as proposed, the battery does not eliminate the need to replace the Weber #2 230/60 kV bank because the overload of this equipment merely decreases from 129% to 121% in year 2014 (first year of in-service date for the battery). In order to address this problem, 48 MW of batteries would need to be installed in the first year (2014) at a cost of approximately $72 million. This total cost for the battery storage project needs to be compared against PG&E's total cost for the two projects: Stockton "A"-Weber # 1 and #2 60 kV lines reconductor at $5-10 million, plus Weber #2 230/60 kV Bank replacement at $8-15 million. The PG&E proposed projects, at a cost of $13-25 million, are still the least expensive alternative, by far.

Guernsey

Your claim that cost of WGD's Guernsey solution is significantly lower than the cost of the alternative adopted by the ISO is without merit because it fails to consider the significant additional costs that would have to be incurred if the ISO were to approve the battery storage project.

The Corcoran 115 kV line to the Corcoran 70 kV transformer bank #2 was identified as overloaded under NERC Category A conditions in the 2014 and 2019 summer peak case. The mitigation solution adopted by the ISO is to replace the transformer with a higher capacity transformer. The estimated cost of the transformer replacement project is $10-$20 million. In its letter, WGD incorrectly assumes that the costs of PG&E's previously identified Guernsey 70KV to 115 kV conversion project alternative should be included as part of the total PG&E project costs. However, the ISO has not found an identified reliability need for the conversion project. Thus, WGD's conclusions are incorrect.

The initial capital cost of the project proposed by WGD is $10,500,000; with additional capital costs of $10,500,000 to be incurred as the battery capabilities increase from 7 MW to 14 MW. These cost estimates fail to include the significant additional costs that would have to be incurred -- for two Special Protection Schemes (SPS) and replacement of an existing transformer -- if the ISO were to approve the battery project, as well as the increased operational complexity that would result from such a decision. ISO staff conducted a technical analysis of the proposed battery storage resource as an option to determine whether PG&E should be directed to install battery storage to address reliability concerns in this area. Staff found that the analysis provided by WGD failed to take into account the Henrietta SPS. The existing NERC compliant Henrietta SPS drops the Henrietta 70 kV system for the double circuit tower line outage of the Gates-McCall, and Gates-Gregg 230 kV lines. Implementation of the proposed storage project would cause a voltage collapse when the Henrietta SPS was triggered because the entire 70 kV system in the area would end up radially connected to Corcoran 70 kV source. Potential redesigns to the proposed storage project (*e.g.*, an SPS to enable remote tripping of the Corcoran-Guernsey 70 kV line) are counter to ISO principles for SPS design in the ISO Planning Standards. Also, staff found during its analysis that the existing Corcoran transformer would be overloaded during its contingency conditions if the Corcoran and Henrietta 70 kV systems were operated in parallel as suggested by WGD. More specifically, for the double circuit tower line outage of the Gates-McCall, and Helms-

McCall 230 kV lines, the existing Corcoran transformer would be overloaded by 150% during low hydro conditions in 2019. Based on this finding, the ISO concluded that a second SPS would be necessary. SPS mechanisms of this nature typically cost in the range of $ 3 million to $ 5 million dollars. WGD's cost estimates fail to include these additional costs. Also, SPS systems require additional NERC compliance studies to determine the consequences of their failure to operate. They require special procedures and operator training to ensure that they are cutout during normal switching operations and to ensure that operators know when the system has responded as designed as opposed to having sympathetic tripping or mis-operation.

WGD also fails to account for the fact that if the ISO were to approve the battery storage project, additional costs would still have to be incurred to replace the existing transformer. In that regard, the transformer that is being replaced as part of the ISO-approved project dates back to 1931 and has been slated for replacement in 2013. The project approved by the ISO not only solves the identified reliability need, it replaces the transformer. WGD fails to include the costs of a replacement transformer in its cost analysis. Thus, WGD significantly understates the costs that would be incurred if the ISO were to approve the battery storage solution. WGD's project is significantly understated.

In addition to the additional complexity and costs associated with the two new SPS elements that would be required with the Guernsey storage project (as well as the cost of a replacement transformer), complex operating procedures would need to be developed and closely followed by operators to ensure that the battery is discharged at all times and in exact amounts when needed for reliability and charged only at the times and in exact amounts that would not cause reliability problems. These added operating procedures would add daily and hourly tasks for engineers and grid operators and would distract them from more critical reliability functions, all of which are not required by a transformer.

Thus, even putting aside the potential concern that installation of battery storage might adversely affect Helms pumping , the battery is not the preferred solution for solving the reliability needs identified by the ISO.

Auburn

In your letter, you object to the rejection of WGD's proposal, claiming that it would produce a net savings to ratepayers of $134 million (based on an initial capital cost of $43.5 million) compared to PG&E's Atlantic-Placer Voltage Conversion project that has a capital cost of $50-60 million. As an initial matter, the ISO has not yet approved a project(s) to meet the myriad of reliability needs in this area. The ISO will continue to study viable options that can provide a comprehensive, long-term solution to these needs. Even if the ISO ultimately were to approve a storage battery as an element of that comprehensive solution, WGD would not be able to own or maintain that facility under the terms of the ISO tariff. Below, we offer the following comments on the specific claims raised in your letter comparing WGD's proposed project with PG&E's Atlantic-Placer Voltage Conversion project.

The Placer area is very complex with both peak and off-peak transmission constraints. As such, it requires a comprehensive long-term solution that solves all of the constraints, not a solution that addresses only a single constraint. The power flows in and through this area are driven not only by load levels, but also by hydro generation output and the Drum-Summit intertie flows. Due to these factors, the operation of this system is extremely dynamic with multiple constraints that need to be mitigated throughout the day. It is not clear, at this time, that that a battery storage resource can charge enough throughout the daily cycle in order to help mitigate the binding constraints in the area throughout the day. For the reasons specified above this area is one of the worst areas to add load even during off-peak hours.

The project does not constitute a comprehensive long-term solution for the overall problems in the Placer area and the greater Atlantic-Placer area. Because the reliability needs in this area are interrelated, the ultimate solution or solutions need to complement each other and ensure full compliance with reliability standards. On the other hand, PG&E's Atlantic-Placer Voltage Conversion project solves sixteen peak reliability problems in the area (see tables 3-3.4.6 through 3-3.4.9 in the 2010 ISO Transmission Plan) along with other off peak problems driven by hydro and import patterns. Thus, your cost analysis is not an "apples-to-apples" comparison of the two projects. Because your analysis fails to account for the costs of the additional projects that would be needed to solve the reliability problems that the battery does not solve (but the Atlantic-Placer Voltage Conversion project does), the costs associated with approval of the WGD project are substantially understated by comparison.

At this time, the ISO does not consider the battery project as a comprehensive long-term solution, however, the ISO will further assess the Atlantic - Placer Voltage Conversion project along with other possible options (including battery storage) in the next planning cycle. As indicated above, however, if the ISO were to find that a battery storage resource is needed, PG&E would be the entity to construct and own it under the ISO tariff. Thus, WGD's proposal is rejected to the extent that it contemplates that WGD would own, construct, finance and maintain any battery storage facility found to be needed.

Potrero

Your letter states that ISO Staff's conclusion that San Francisco has no reliability violation conflicts with other information. Specifically, you refer to a September 15, 2009 report that purportedly concluded that San Francisco will need 25 MW to comply with reliability criteria after TransBay cable is in service. You state that the draft Transmission Plan reported that load in the area was lower than previously forecast but failed to explain this significant change. Finally, you question why Potrero 5, 6 and 7 are still needed if San Francisco is not expected to have any reliability problems.

The ISO is not aware of any September 15, 2009 report that contains the information to which you refer. There is a May 1, 2009 report that identifies a 25 MW generation need in San Francisco. That 25 MW generation need was based on a previous estimate of the new ratings of Martin-Bayshore-Potrero cables #1 and #2 following recabling. In August 2009, PG&E provided updated ratings which were approximately 30% higher than what was estimated earlier. The ISO reviewed those updated ratings and found them to be reasonable. The draft Transmission Plan used those updated ratings and, as a result, the ISO found there were no overloaded facilities that required generation at Potrero to mitigate. In its February 16, 2010 presentation to stakeholders on San Francisco results, the ISO staff listed this conclusion as a bullet in the Key Findings section. The 2010 Transmission Plan posted on March 9, 2010 includes San Francisco study results, and it clearly states in section 3.3.5.4 (page 158) and section 7.3 (page 293) that Potrero 4, 5 and 6 can be released from their RMR designation as a result of the re-cabling. There is no Potrero 7 as you state in your letter.

Weedpatch

The letter comments on the ISO's rejection of the Weedpatch battery project and notes that the reliability concerns in Weedpatch are addressed by opening up Circuit Breaker 42. As a point of clarification, the summer setup operating procedure to open circuit breaker 42 at Weedpatch is an existing operating procedure that was used in real-time operations during summer 2009. It is fully compliant with NERC standards, and the ISO will continue to rely on it. Thus, there is no need for any new reliability transmission project in this area, and WGD has not submitted any evidence to the contrary.

ATTACHMENT T

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the attachment A (technical data) to the CAISO contact listed in section 3. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to be considered in the CAISO Transmission Plan. This submission is for (check one)[1]:

- ☒ Reliability Transmission Project (refer to section 1 of attachment A)
- ☐ Merchant Transmission Facility (refer to section 1 of attachment A)
- ☐ Economic Transmission Project (refer to section 1 of attachment A)
- ☐ Location Constrained Resource Interconnection Facility (LCRIF) (refer to sections 1 & 2 of attachment A)
- ☐ Project to preserve Long-term Congestion Revenue Rights (CRR) (refer to section 1 of attachment A)
- ☐ Economic Planning Study Request (refer to section 3 of attachment A)
- ☐ Others (refer to section 4 of attachment A)

2. For the submission of a Reliability, Merchant, Economic, LCRIF, and CRR project, the project sponsor is

- ☒ Seeking ISO approval in this planning cycle
- ☐ Submitting for information only (not requiring ISO approval in this planning cycle)

3. Please provide the following basic information about this submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Coppermine 70kV Energy Storage Project**

Submission Date: **November 30, 2009**

b. Project locations or the proposed interconnection point(s) :

PG&E's Coppermine 70kV Substation

c. Project capacity (Net MW):

Initially 10MW of energy storage will be installed at the Coppermine 70kV substation. Additional storage will be added every 5 years to maintain system reliability and account for load growth. The table below outlines the amount of storage that is required from years 1-30.

[1] Please contact the ISO staff at requestwindow@caiso.com for any questions regarding the definitions of these submission categories in this form to the ISO

Coppermine 70kV	
Year	Storage Device Size (MW)
5	10
10	15
15	22
20	29
25	36
30	45

Table 1: Required Storage Device Size

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project e.g. overall scope, objectives etc.

PG&E's 2009 Electric Transmission Grid Expansion Plan identified that for summer peak conditions an outage of the Borden-Coppermine 70kV line when Friant generation is offline, will cause low voltages in the Coppermine 70kV area. This overload was present in the 2009 WECC base case.

PG&E is proposing a conversion of the Borden-Coppermine 70kV system to 115kV, a new source from the Herndon Substation, a new Coppermine 115kV/70kV bank, and a new Herndon-Coppermine 115kV line. PG&E is proposing an in-service date of May 2016. PG&E is estimating the cost to be between $25M-40M.

WGD is proposing a less costly alternative which includes installing a 10MW battery storage device at the Coppermine 70kV substation in 2010, followed by six additional battery storage installations (one every 5 years) to account for load growth. This project will resolve reliability concerns for 30 years.

Economic analyses indicate that the WGD solution has a levelized annual revenue requirement of $13.2M compared to $16.7M for PG&E. The overall project cost was calculated at $164.3M NPV compared to $207.1M NPV for PG&E with an additional $17.8M in Power Quality and Reliability services. The PG&E to WGD cost ratio is 1.37% indicating a large economic benefit as the WGD project is 37% less expensive than the PG&E proposed solution.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**12 / 30 / 2010**
Proposed Trial Operation date:	**12 / 30 / 2010**
Proposed Commercial Operation date:	**12 / 30 / 2010**
Proposed Term of Service:	**30 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title: **Managing Member**

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
CAISO TRANSMISSION PLANNING PROCESS
REQUEST WINDOW SUBMISSION FORM

Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

4. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Young
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

5. This Request is submitted by: **Western Grid Development, LLC**

Name of the Customer:	**Western Grid Development, LLC**
By (signature):	(John Dizard)
Name (type or print):	**John Dizard**
Title:	Managing Member
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	New York, NY
Zip Code:	10128
Phone Number:	212-937-4622
Email Address:	dizard@gmail.com
Date:	November 30, 2009

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

This section applies to all transmission project submissions. It does not apply to Economic Planning Study Requests.

Any transmission project, including those seeking cost recovery through Long-term Congestion Revenue Rights, whether submitted by a PTO, non-PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[2]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route

Technical Data

- Network model for power flow study in GE-PSLF format. In some cases, Dynamic models for stability study in GE-PSLF format may also be required

Planning Level Cost Data[3]

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[2] This appendix lists the minimum amount of data required by the ISO for the first screening purposes. Additional data may be requested by the ISO later during the course of project evaluation

[3] Not required for Merchant Transmission Facilities

2. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets applicable reliability requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

3. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives, must be provided to CAISO by the closing date of Request Window.

4. Submission under "Other" category

This category of submission includes other type of proposals that may be considered as alternatives in the transmission planning process such as generation, demand response programs, new technologies etc. However, the ISO encourages project sponsors to contact CAISO staff prior to submitting these proposals through the Request Window.

General Data

Description of Project

Please see the attached report which includes a full reliability analysis and economic analysis on all WGD proposed projects.

The PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) included a single line diagram of the Coppermine 70kV area as shown below in figure 1.

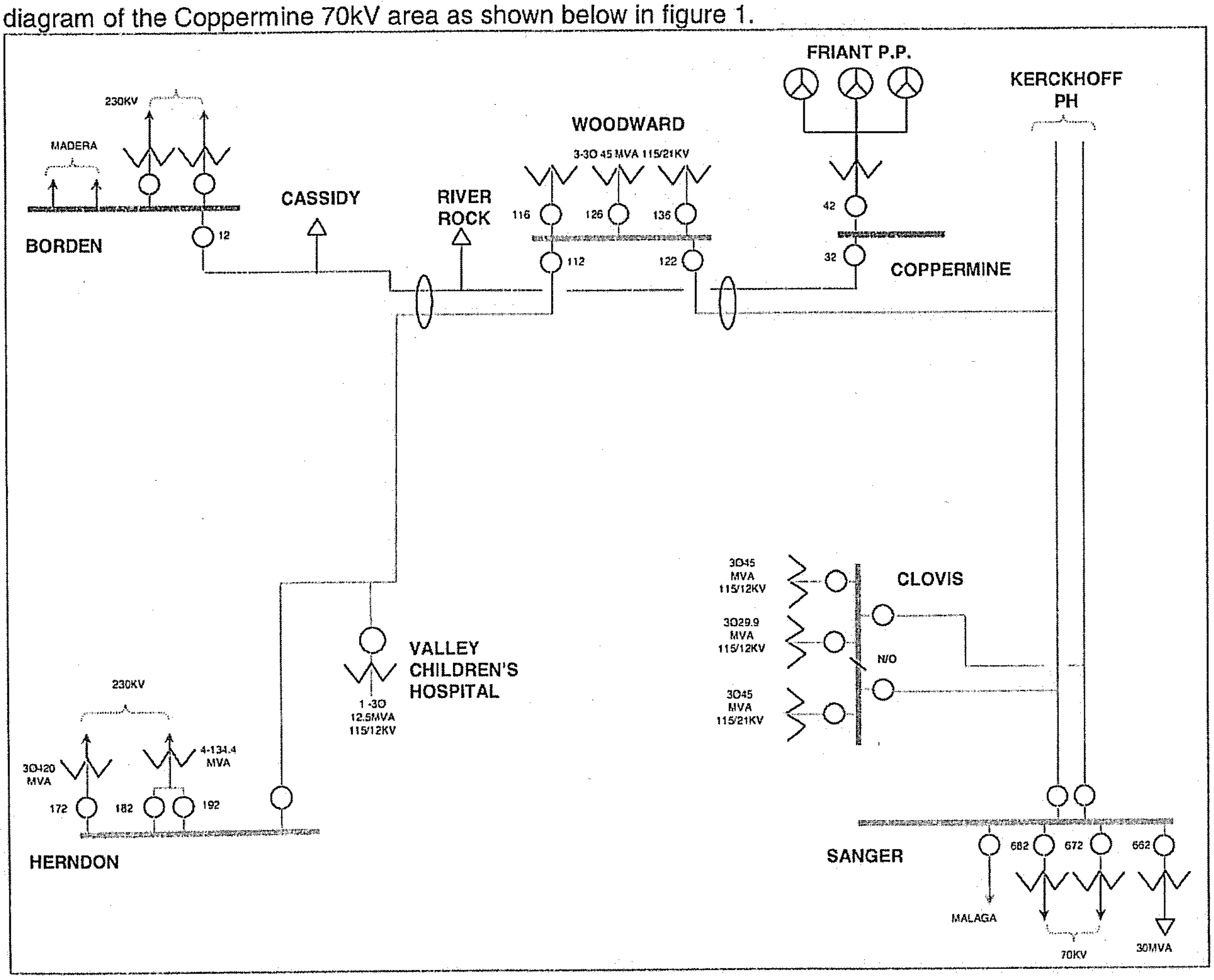


Figure 1: Coppermine 70 kV Area

PG&E's 2009 Electric Transmission Grid Expansion Plan identified that for summer peak conditions an outage of the Borden-Coppermine 70kV line when Friant generation is offline, will cause low voltages in the Coppermine 70kV area. This overload was present in the 2009 WECC base case.

PG&E is proposing a conversion of the Borden-Coppermine 70kV system to 115kV, a new source from the Herndon Substation, a new Coppermine 115kV/70kV bank, and a new Herndon-Coppermine 115kV line. PG&E is proposing an in-service date of May 2016. PG&E is estimating the cost to be between $25M-40M.

WGD is proposing a less costly alternative which includes installing a 10MW battery storage device at the Coppermine 70kV substation in 2010, followed by six additional battery storage installations (one every 5 years) to account for load growth. This project will resolve reliability concerns for 30 years.

Economic analyses indicate that the WGD solution has a levelized annual revenue requirement of \$13.2M compared to \$16.7M for PG&E. The overall project cost was calculated at \$164.3M NPV compared to \$207.1M NPV for PG&E with an additional \$17.8M in Power Quality and Reliability services. The PG&E to WGD cost ratio is 1.37% indicating a large economic benefit as the WGD project is 37% less expensive than the PG&E proposed solution.

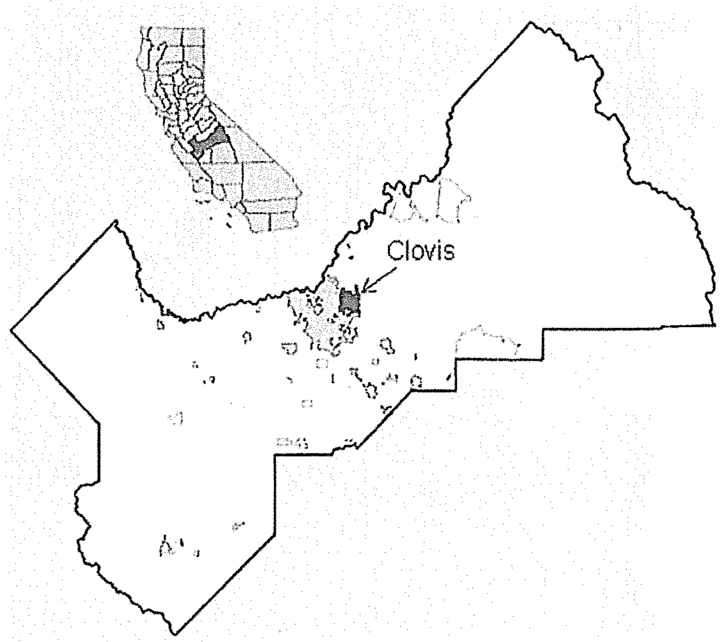


Figure 2: Coppermine Geographical Location

Required Storage Device Size

A load flow study was performed using the WECC 2009 heavy summer base case. The WECC 2009 heavy summer base case showed low voltages after the loss of the Corcoran-Guernsey 70kV line when the Friant generation is offline. This can be seen in Figure 3 below.

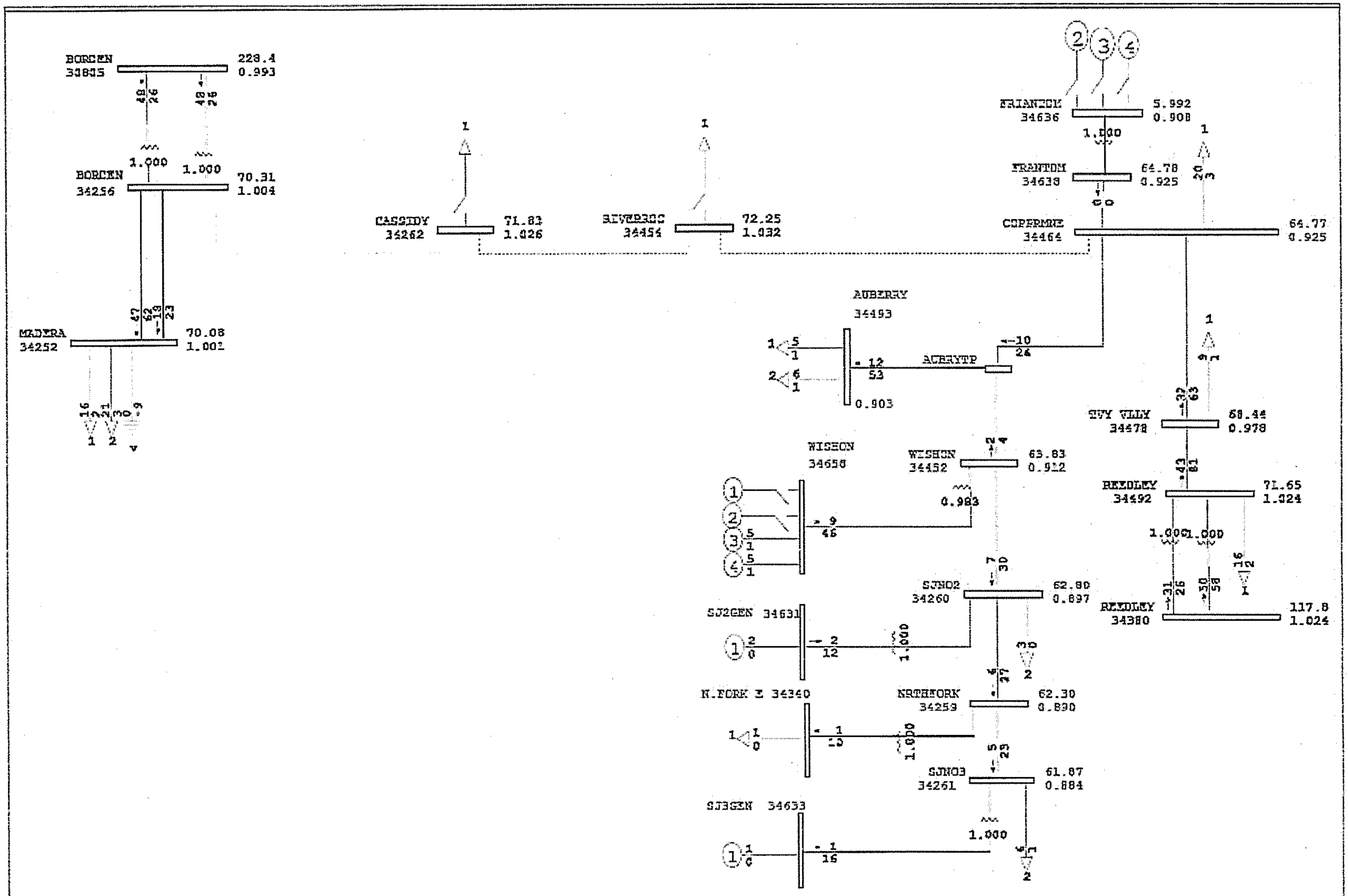


Figure 3: WECC 2009 Post Contingency Coppermine Voltages

It was determined that approximately 10MW of battery storage device would be required to keep the voltage above 0.9PU in the Coppermine 70kV pocket thru 2015. 10MW of storage would be installed in 2010, and this would be sufficient to keep the voltages above 0.9PU until 2015. In 2015 additional battery storage will be installed to meet load levels for the next five years. This cycle will continue until enough batter storage is installed to cover a 30 year project life.

To avoid the low voltages in the Coppermine 70kV area a 10MW battery storage device was placed at the Coppermine70kV substation. Table 2 below shows the assumed 2015 load (5 year). Figure 4 shows the post contingency voltages after a storage device placed at the Coppermine 70kV substation.

Station Name	Assumed 2010 Load (MW)	5 year
SJNO3	6	6.4
SJNO2	3	3.2
AUBERRY	11	11.7
COPPRMNE	20	21.3
TVY VLLY	9	9.6
REEDLEY	16	17.1
Total Load	65.0	69.3
Required Battery		10

Table 2: Projected Coppermine 2015 Load

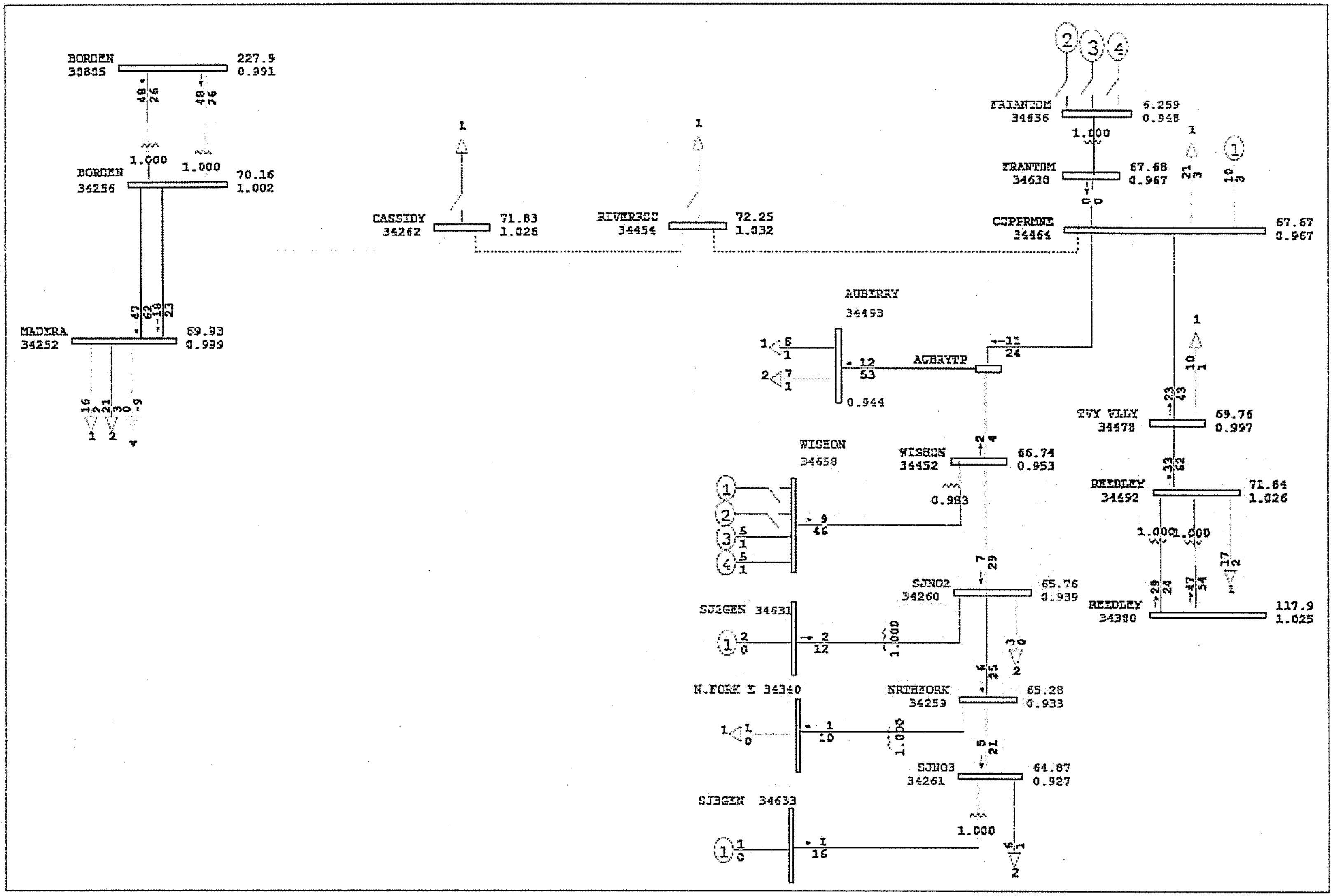


Figure 4: Coppermine 70kV Pocket 2015 (5 Year) Projection

The next step involved calculating the required battery size to replace the PG&E alternative for 30 years. The Coppermine70kV load was increased at a rate of 3% per year. This rate was found in the CEC Staff Final Energy Demand Forecast Report. In the report the CEC states that 1.3% is the forecasted average annual growth in load from 2008-2020 as shown below in table 3.

Business-as-Usual Reference Case						
Source: CEC Staff Final Energy Demand Forecast Report, October 2007						
Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	21,886	1.3%	81,532	95,598	1.3%
SCE	21,476	25,777	1.5%	87,966	106,018	1.6%
SDG&E	3,712	4,423	1.5%	18,687	22,651	1.6%
SMUD	3,174	3,741	1.4%	11,887	13,990	1.4%
LADWP	5,717	6,010	0.4%	28,004	29,592	0.5%
NorCalMunis	5,077	5,942	1.3%	35,720	39,440	0.8%
SoCalMunis	5,079	5,959	1.3%	35,148	38,276	0.7%
California	62,946	73,738	1.3%	298,945	345,566	1.2%

Table 3: CEC Energy Demand Forecast

It was found that a 45MW battery storage device at the Coppermine 70kV substation was required to keep the voltages in the area above 0.9PU. The 2040 (30 year) Coppermine 70kV load values are in table 4 below, along with the required battery storage sizes to accommodate the load growth.

Station Name	Assumed 2010 Load (MW)	5 year	10 Year	15 year	20 year	25 year	2040 Expected Values (30 Year)
SJNO3	6	6.4	6.8	7.3	7.8	8.3	8.8
SJNO2	3	3.2	3.4	3.6	3.9	4.1	4.4
AUBERRY	11	11.7	12.5	13.4	14.2	15.2	16.2
COPPRMNE	20	21.3	22.8	24.3	25.9	27.6	29.5
TVY VLLY	9	9.6	10.2	10.9	11.7	12.4	13.3
REEDLEY	16	17.1	18.2	19.4	20.7	22.1	23.6
Total Load	65.0	69.3	74.0	78.9	84.2	89.8	95.8
Required Battery		10	15	22	29	36	45.0

Table 4: Projected 30 Year Storage Device Size

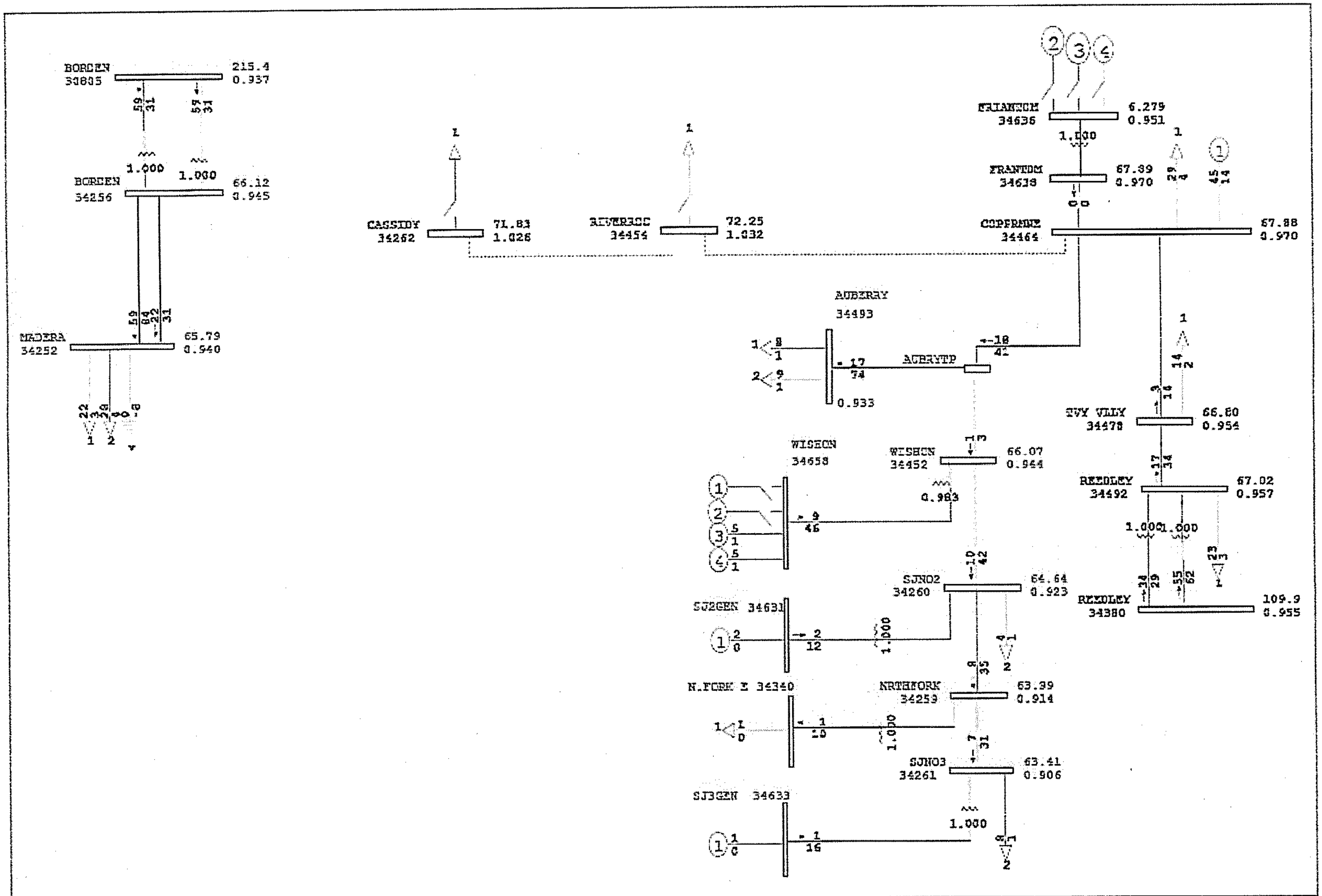


Figure 5: Coppermine 70kV Pocket 2040 (30 Year) Projection

Economic Analysis

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

WGD proposes using a service life of 30 years. Table 5 below shows the WGD ratemaking assumptions. For comparative purposes, these assumptions will match those listed by PG&E as shown in table 6.

Install Date	Assumption	Value	Pre-Calculations	Note
	Battery Cost ($/MW)	$1,500,000.00		
Year 1	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$15,000,000.0**	-	10MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$500,000.00	
Year 5	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$8,227,196.9**	-	(15-10)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$274,239.90	
Year 10	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$9,258,146.7	-	(22-15)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$308,604.89	
Year 15	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$10,390,035.0**	-	(29-22)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$346,334.50	
Year 20	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$11,631,741.2**	-	(36-29)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$387,724.71	
Year 25	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$12,992,880.1**	-	(45-36)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$433,096.00	
	O&M = Operations and Maintanance	17.9%	-	
	A&G = Administrative and General	7.30%	-	
	Cost of Capital	9.27%	-	
	Taxes	22.4%	-	
	i = Interest Rate	7.00%	-	

Table 5: WGD Ratemaking Assumptions

Assumption	Value	Pre-Calculations
n = Asset Life (Years)	30	-
Salvage Value ($)	$0.0	-
Capital Cost ($)	$40,000,000.0	-
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$1,333,333.33
O&M = Operations and Maintanance	17.9%	-
A&G = Administrative and General	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 6: PG&E Ratemaking Assumptions

Using the assumptions listed above, our analysis indicates that the WGD solution has a levelized annual revenue requirement of $13.2M compared to $16.7M for PG&E. The overall project cost was calculated at $164.3M NPV compared to $207.1M NPV for PG&E with an additional $17.8M in Power Quality and Reliability services. The PG&E to WGD cost ratio is 1.37% indicating a large economic benefit as the WGD project is 37% less expensive than the PG&E proposed solution.

Year (n)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Power Quality & Reliability Services	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 15,000,000	$ 500,000	$ 1,390,500	$ 2,686,000	$ 1,095,000	$ 3,360,000	$ (723,887)	$ 9,030,500	$ 8,439,720	$ 13,242,010
1	$ 14,500,000	$ 500,000	$ 1,344,150	$ 2,595,500	$ 1,058,500	$ 3,248,000	$ (723,887)	$ 8,746,150	$ 7,639,226	
2	$ 14,000,000	$ 500,000	$ 1,297,800	$ 2,506,000	$ 1,022,000	$ 3,136,000	$ (723,887)	$ 8,461,800	$ 6,907,349	
3	$ 13,500,000	$ 500,000	$ 1,251,450	$ 2,416,500	$ 985,500	$ 3,024,000	$ (723,887)	$ 8,177,450	$ 6,238,537	
4	$ 13,000,000	$ 500,000	$ 1,205,100	$ 2,327,000	$ 949,000	$ 2,912,000	$ (723,887)	$ 7,893,100	$ 5,627,671	
5	$ 20,727,197	$ 774,240	$ 1,921,411	$ 3,710,168	$ 1,513,085	$ 4,642,892	$ (1,120,924)	$ 12,561,797	$ 8,370,456	
6	$ 19,952,957	$ 774,240	$ 1,849,639	$ 3,571,579	$ 1,456,566	$ 4,469,462	$ (1,120,924)	$ 12,121,487	$ 7,548,653	
7	$ 19,178,717	$ 774,240	$ 1,777,867	$ 3,432,990	$ 1,400,046	$ 4,296,033	$ (1,120,924)	$ 11,681,176	$ 6,798,551	
8	$ 18,404,477	$ 774,240	$ 1,706,095	$ 3,294,401	$ 1,343,527	$ 4,122,603	$ (1,120,924)	$ 11,240,866	$ 6,114,286	
9	$ 17,630,237	$ 774,240	$ 1,634,323	$ 3,155,812	$ 1,287,007	$ 3,949,173	$ (1,120,924)	$ 10,800,556	$ 5,490,455	
10	$ 26,114,144	$ 1,082,845	$ 2,420,781	$ 4,674,432	$ 1,906,333	$ 5,849,568	$ (1,567,715)	$ 15,933,959	$ 7,570,109	
11	$ 25,031,299	$ 1,082,845	$ 2,320,401	$ 4,480,603	$ 1,827,285	$ 5,607,011	$ (1,567,715)	$ 15,318,145	$ 6,801,439	
12	$ 23,948,455	$ 1,082,845	$ 2,220,022	$ 4,286,773	$ 1,748,237	$ 5,364,454	$ (1,567,715)	$ 14,702,331	$ 6,100,945	
13	$ 22,865,610	$ 1,082,845	$ 2,119,642	$ 4,092,944	$ 1,669,190	$ 5,121,897	$ (1,567,715)	$ 14,086,517	$ 5,462,994	
14	$ 21,782,765	$ 1,082,845	$ 2,019,262	$ 3,899,115	$ 1,590,142	$ 4,879,339	$ (1,567,715)	$ 13,470,703	$ 4,882,403	
15	$ 31,089,955	$ 1,429,179	$ 2,882,039	$ 5,565,102	$ 2,269,567	$ 6,964,150	$ (2,069,129)	$ 19,110,037	$ 6,473,231	
16	$ 29,660,776	$ 1,429,179	$ 2,749,554	$ 5,309,279	$ 2,165,237	$ 6,644,014	$ (2,069,129)	$ 18,297,263	$ 5,792,445	
17	$ 28,231,597	$ 1,429,179	$ 2,617,069	$ 5,053,456	$ 2,060,907	$ 6,323,878	$ (2,069,129)	$ 17,484,488	$ 5,173,029	
18	$ 26,802,417	$ 1,429,179	$ 2,484,584	$ 4,797,633	$ 1,956,576	$ 6,003,741	$ (2,069,129)	$ 16,671,714	$ 4,609,868	
19	$ 25,373,238	$ 1,429,179	$ 2,352,099	$ 4,541,810	$ 1,852,246	$ 5,683,605	$ (2,069,129)	$ 15,858,940	$ 4,098,251	
20	$ 35,575,800	$ 1,816,904	$ 3,297,877	$ 6,368,068	$ 2,597,033	$ 7,968,979	$ (2,630,466)	$ 22,048,861	$ 5,325,089	
21	$ 33,758,896	$ 1,816,904	$ 3,129,450	$ 6,042,842	$ 2,464,399	$ 7,561,993	$ (2,630,466)	$ 21,015,588	$ 4,743,495	
22	$ 31,941,992	$ 1,816,904	$ 2,961,023	$ 5,717,617	$ 2,331,765	$ 7,155,006	$ (2,630,466)	$ 19,982,315	$ 4,216,207	
23	$ 30,125,088	$ 1,816,904	$ 2,792,596	$ 5,392,391	$ 2,199,131	$ 6,748,020	$ (2,630,466)	$ 18,949,042	$ 3,736,739	
24	$ 28,308,184	$ 1,816,904	$ 2,624,169	$ 5,067,165	$ 2,066,497	$ 6,341,033	$ (2,630,466)	$ 17,915,768	$ 3,300,966	
25	$ 39,484,160	$ 2,250,000	$ 3,660,182	$ 7,067,665	$ 2,882,344	$ 8,844,452	$ (3,257,491)	$ 24,704,642	$ 4,254,028	
26	$ 37,234,160	$ 2,250,000	$ 3,451,607	$ 6,664,915	$ 2,718,094	$ 8,340,452	$ (3,257,491)	$ 23,425,067	$ 3,769,805	
27	$ 34,984,160	$ 2,250,000	$ 3,243,032	$ 6,262,165	$ 2,553,844	$ 7,836,452	$ (3,257,491)	$ 22,145,492	$ 3,330,731	
28	$ 32,734,160	$ 2,250,000	$ 3,034,457	$ 5,859,415	$ 2,389,594	$ 7,332,452	$ (3,257,491)	$ 20,865,917	$ 2,932,972	
29	$ 30,484,160	$ 2,250,000	$ 2,825,882	$ 5,456,665	$ 2,225,344	$ 6,828,452	$ (3,257,491)	$ 19,586,342	$ 2,573,001	
TOTAL	$ 761,424,602	$ 39,265,840	$ 70,584,061	$ 136,295,004	$ 55,583,996	$ 170,559,111	$ (56,848,061)	$ 472,288,011	$ 164,320,650	

Table 7: WGD Alternative Project Cost

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement	Levilized income
0	$ 40,000,000	$ 1,333,333	$ 3,708,000	$ 7,160,000	$ 2,920,000	$ 8,960,000	$ 24,081,333	$ 22,505,919	$ 16,689,231	$ 2,503,063
1	$ 38,666,667	$ 1,333,333	$ 3,584,400	$ 6,921,333	$ 2,822,667	$ 8,661,333	$ 23,323,067	$ 20,371,270		
2	$ 37,333,333	$ 1,333,333	$ 3,460,800	$ 6,682,667	$ 2,725,333	$ 8,362,667	$ 22,564,800	$ 18,419,598		
3	$ 36,000,000	$ 1,333,333	$ 3,337,200	$ 6,444,000	$ 2,628,000	$ 8,064,000	$ 21,806,533	$ 16,636,100		
4	$ 34,666,667	$ 1,333,333	$ 3,213,600	$ 6,205,333	$ 2,530,667	$ 7,765,333	$ 21,048,267	$ 15,007,123		
5	$ 33,333,333	$ 1,333,333	$ 3,090,000	$ 5,966,667	$ 2,433,333	$ 7,466,667	$ 20,290,000	$ 13,520,084		
6	$ 32,000,000	$ 1,333,333	$ 2,966,400	$ 5,728,000	$ 2,336,000	$ 7,168,000	$ 19,531,733	$ 12,163,382		
7	$ 30,666,667	$ 1,333,333	$ 2,842,800	$ 5,489,333	$ 2,238,667	$ 6,869,333	$ 18,773,467	$ 10,926,329		
8	$ 29,333,333	$ 1,333,333	$ 2,719,200	$ 5,250,667	$ 2,141,333	$ 6,570,667	$ 18,015,200	$ 9,799,075		
9	$ 28,000,000	$ 1,333,333	$ 2,595,600	$ 5,012,000	$ 2,044,000	$ 6,272,000	$ 17,256,933	$ 8,772,550		
10	$ 26,666,667	$ 1,333,333	$ 2,472,000	$ 4,773,333	$ 1,946,667	$ 5,973,333	$ 16,498,667	$ 7,838,398		
11	$ 25,333,333	$ 1,333,333	$ 2,348,400	$ 4,534,667	$ 1,849,333	$ 5,674,667	$ 15,740,400	$ 6,988,926		
12	$ 24,000,000	$ 1,333,333	$ 2,224,800	$ 4,296,000	$ 1,752,000	$ 5,376,000	$ 14,982,133	$ 6,217,053		
13	$ 22,666,667	$ 1,333,333	$ 2,101,200	$ 4,057,333	$ 1,654,667	$ 5,077,333	$ 14,223,867	$ 5,516,261		
14	$ 21,333,333	$ 1,333,333	$ 1,977,600	$ 3,818,667	$ 1,557,333	$ 4,778,667	$ 13,465,600	$ 4,880,553		
15	$ 20,000,000	$ 1,333,333	$ 1,854,000	$ 3,580,000	$ 1,460,000	$ 4,480,000	$ 12,707,333	$ 4,304,413		
16	$ 18,666,667	$ 1,333,333	$ 1,730,400	$ 3,341,333	$ 1,362,667	$ 4,181,333	$ 11,949,067	$ 3,782,768		
17	$ 17,333,333	$ 1,333,333	$ 1,606,800	$ 3,102,667	$ 1,265,333	$ 3,882,667	$ 11,190,800	$ 3,310,954		
18	$ 16,000,000	$ 1,333,333	$ 1,483,200	$ 2,864,000	$ 1,168,000	$ 3,584,000	$ 10,432,533	$ 2,884,682		
19	$ 14,666,667	$ 1,333,333	$ 1,359,600	$ 2,625,333	$ 1,070,667	$ 3,285,333	$ 9,674,267	$ 2,500,014		
20	$ 13,333,333	$ 1,333,333	$ 1,236,000	$ 2,386,667	$ 973,333	$ 2,986,667	$ 8,916,000	$ 2,153,331		
21	$ 12,000,000	$ 1,333,333	$ 1,112,400	$ 2,148,000	$ 876,000	$ 2,688,000	$ 8,157,733	$ 1,841,308		
22	$ 10,666,667	$ 1,333,333	$ 988,800	$ 1,909,333	$ 778,667	$ 2,389,333	$ 7,399,467	$ 1,560,894		
23	$ 9,333,333	$ 1,333,333	$ 865,200	$ 1,670,667	$ 681,333	$ 2,090,667	$ 6,641,200	$ 1,309,290		
24	$ 8,000,000	$ 1,333,333	$ 741,600	$ 1,432,000	$ 584,000	$ 1,792,000	$ 5,882,933	$ 1,083,926		
25	$ 6,666,667	$ 1,333,333	$ 618,000	$ 1,193,333	$ 486,667	$ 1,493,333	$ 5,124,667	$ 882,445		
26	$ 5,333,333	$ 1,333,333	$ 494,400	$ 954,667	$ 389,333	$ 1,194,667	$ 4,366,400	$ 702,686		
27	$ 4,000,000	$ 1,333,333	$ 370,800	$ 716,000	$ 292,000	$ 896,000	$ 3,608,133	$ 542,671		
28	$ 2,666,667	$ 1,333,333	$ 247,200	$ 477,333	$ 194,667	$ 597,333	$ 2,849,867	$ 400,585		
29	$ 1,333,333	$ 1,333,333	$ 123,600	$ 238,667	$ 97,333	$ 298,667	$ 2,091,600	$ 274,767		
TOTAL	$ 620,000,000	$ 40,000,000	$ 57,474,000	$ 110,980,000	$ 45,260,000	$ 138,880,000	$ 392,594,000	$ 207,097,355		

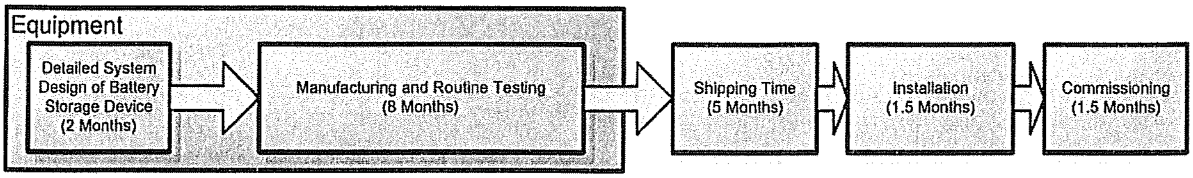
Table 8: PG&E Alternative Project Cost

Power Quality & Reliability Services	PV	
$ (723,887)	0.934579439	$ (676,529.89)
$ (723,887)	0.873438728	$ (632,270.93)
$ (723,887)	0.816297877	$ (590,907.41)
$ (723,887)	0.762895212	$ (552,249.92)
$ (723,887)	0.712986179	$ (516,121.42)
$ (1,120,924)	0.666342224	$ (746,919.24)
$ (1,120,924)	0.622749742	$ (698,055.36)
$ (1,120,924)	0.582009105	$ (652,388.19)
$ (1,120,924)	0.543933743	$ (609,708.59)
$ (1,120,924)	0.508349292	$ (569,821.11)
$ (1,567,715)	0.475092796	$ (744,809.87)
$ (1,567,715)	0.444011959	$ (696,083.99)
$ (1,567,715)	0.414964448	$ (650,545.78)
$ (1,567,715)	0.387817241	$ (607,986.71)
$ (1,567,715)	0.36244602	$ (568,211.88)
$ (2,069,129)	0.338734598	$ (700,885.44)
$ (2,069,129)	0.31657439	$ (655,033.12)
$ (2,069,129)	0.295863916	$ (612,180.48)
$ (2,069,129)	0.276508333	$ (572,131.29)
$ (2,069,129)	0.258419003	$ (534,702.14)
$ (2,630,466)	0.241513087	$ (635,292.04)
$ (2,630,466)	0.225713165	$ (593,730.88)
$ (2,630,466)	0.210946883	$ (554,888.67)
$ (2,630,466)	0.19714662	$ (518,587.54)
$ (2,630,466)	0.184249178	$ (484,661.25)
$ (3,257,491)	0.172195493	$ (560,925.34)
$ (3,257,491)	0.160930367	$ (524,229.29)
$ (3,257,491)	0.150402212	$ (489,933.92)
$ (3,257,491)	0.140562815	$ (457,882.17)
$ (3,257,491)	0.131367117	$ (427,927.26)
	TOTAL	**$ (17,835,601)**

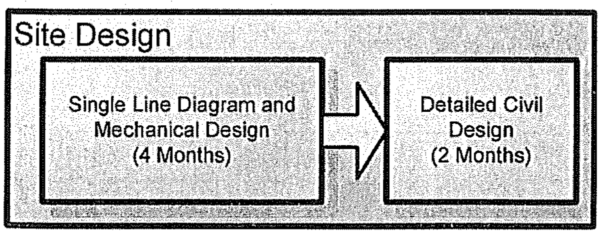
Table 9: Power Quality & Reliability Service Benefit

Construction schedule and expected online date:

The chart below outlines the estimated schedule of 18 months



During the 10 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Technical Data

The following pieces of technical information are attached to this application:

- Network model for power flow study in GE-PSLF format
  - coppermine.epc
- GE PSLF Batt model and model parameters
  - PSLF_batt_Model.pdf
  - BATT_epcl_parameters.xls
- Sample one line diagram
  - NAS Battery System SLD.pdf

Miscellaneous Data

Proposed entity to construct, own, and finance the project

Western Grid Development, LLC (WGD) will own the storage device project and will act as project manager during construction. WGD will also be responsible for financing the project.

Planned operator of the project

WGD will file to become a PTO under the CAISO tariff and will operate the project upon completion.

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the attachment A (technical data) to the CAISO contact listed in section 3. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to be considered in the CAISO Transmission Plan. This submission is for (check one)[1]:

   ☒ Reliability Transmission Project (refer to section 1 of attachment A)
   ☐ Merchant Transmission Facility (refer to section 1 of attachment A)
   ☐ Economic Transmission Project (refer to section 1 of attachment A)
   ☐ Location Constrained Resource Interconnection Facility (LCRIF) (refer to sections 1 & 2 of attachment A)
   ☐ Project to preserve Long-term Congestion Revenue Rights (CRR) (refer to section 1 of attachment A)
   ☐ Economic Planning Study Request (refer to section 3 of attachment A)
   ☐ Others (refer to section 4 of attachment A)

2. For the submission of a Reliability, Merchant, Economic, LCRIF, and CRR project, the project sponsor is

   ☒ Seeking ISO approval in this planning cycle
   ☐ Submitting for information only (not requiring ISO approval in this planning cycle)

3. Please provide the following basic information about this submission:

   a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

      Project Name: **Madison 115kV Energy Storage Project**

      Submission Date: **November 30, 2009**

   b. Project locations or the proposed interconnection point(s) :

      PG&E's PUTH CRK 115kV Substation

   c. Project capacity (Net MW):

      Initially 5MW of energy storage will be installed at the PUTH CRK 115kV substation. Additional storage will be added every 5 years to maintain system reliability and account for load growth. The table below outlines the amount of storage that is required from years 1-30.

[1] Please contact the ISO staff at requestwindow@caiso.com for any questions regarding the definitions of these submission categories in this form to the ISO

Madison	
Year	Storage Device Size (MW)
5	3
10	6
15	9
20	13
25	17
30	22

Table 1: Required Storage Device Size

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project e.g. overall scope, objectives etc.

The CAISO Reliability Assessment Results (September 15, 2009) for the Central Valley area identified that the Madison-Vaca 115kV line will reach 100.1% of its normal rating by 2014. The CAISO recommends a re-conductor of the line.

WGD is proposing a alternative solution which includes installing a 3MW battery storage device at the PUTH CRK 115kV substation in 2014, followed by six additional battery storage installations (one every 5 years) to account for load growth. This project will resolve reliability concerns for 30 years.

Economic analysis shows that the WGD solution has a levelized annual revenue requirement of $5.7M compared to $5.8M for the recommended Reconductor project. The overall project cost was calculated at $70.2M NPV compared to $72.5M NPV for recommended Reconductor project with an additional $5.3M in Power Quality and Reliability services. The recommended Reconductor project to WGD cost ratio is 1.11% indicating a large economic benefit as the WGD project is 11% less expensive than the recommended Reconductor project proposed solution.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**03 / 30 / 2014**
Proposed Trial Operation date:	**03 / 30 / 2014**
Proposed Commercial Operation date:	**03 / 30 / 2014**
Proposed Term of Service:	**30 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member**
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
CAISO TRANSMISSION PLANNING PROCESS
REQUEST WINDOW SUBMISSION FORM

City, State:	New York, NY
Zip Code:	10128
Phone Number:	917-282-0658
Fax Number:	212-937-4822
Email Address:	dizard@gmail.com

g Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

4. This Request Window submission request shall be submitted to the following CAISO representative

Dana Young
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

5. This Request is submitted by: Western Grid Development, LLC

Name of the Customer: Western Grid Development, LLC

By (signature): ____________ (John Dizard)

Name (type or print): John Dizard

Title:	Managing Member
Company Name.	Western Grid Development, LLC
Street Address:	300 East 94th Street, Suite 221B
City, State:	New York, NY
Zip Code:	10128
Phone Number:	212 937 4822
Email Address:	dizard@gmail.com
Date:	November 30, 2009

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

This section applies to all transmission project submissions. It does not apply to Economic Planning Study Requests.

Any transmission project, including those seeking cost recovery through Long-term Congestion Revenue Rights, whether submitted by a PTO, non-PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[2]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route

Technical Data

- Network model for power flow study in GE-PSLF format. In some cases, Dynamic models for stability study in GE-PSLF format may also be required

Planning Level Cost Data[3]

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[2] This appendix lists the minimum amount of data required by the ISO for the first screening purposes. Additional data may be requested by the ISO later during the course of project evaluation

[3] Not required for Merchant Transmission Facilities

2. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets applicable reliability requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

3. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives, must be provided to CAISO by the closing date of Request Window.

4. Submission under "Other" category

This category of submission includes other type of proposals that may be considered as alternatives in the transmission planning process such as generation, demand response programs, new technologies etc. However, the ISO encourages project sponsors to contact CAISO staff prior to submitting these proposals through the Request Window.

General Data

Description of Project

Please see the attached report which includes a full reliability analysis and economic analysis on all WGD proposed projects.

The CAISO Reliability Assessment Results (September 15, 2009) for the Central Valley area identified that the Madison-Vaca 115kV line will reach 100.1% of its nomal rating by 2014. The CAISO recommends a re-conductor of the line.

WGD is proposing a alternative solution which includes installing a 3MW battery storage device at the PUTH CRK 115kV substation in 2014, followed by six additional battery storage installations (one every 5 years) to account for load growth. This project will resolve reliability concerns for 30 years.

Economic analysis shows that the WGD solution has a levelized annual revenue requirement of $5.7M compared to $5.8M for the recommended Reconductor project. The overall project cost was calculated at $70.2M NPV compared to $72.5M NPV for recommended Reconductor project with an additional $5.3M in Power Quality and Reliability services. The recommended Reconductor project to WGD cost ratio is 1.11% indicating a large economic benefit as the WGD project is 11% less expensive than the recommended Reconductor project proposed solution.

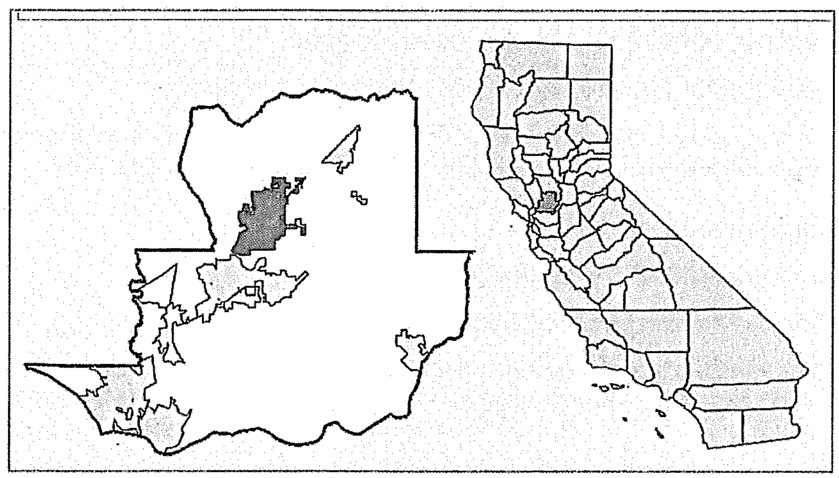


Figure 1: Madison-Vaca Geographic Location

Required Storage Device Size

A load flow study was performed using the WECC 2015 heavy summer base case. The WECC 2015 heavy summer base case was tuned to 2014 load values which according to CAISO studies would put the limiting element at 100.1% of its normal rating by 2014. The tuned results can be seen in Figure 2 below.

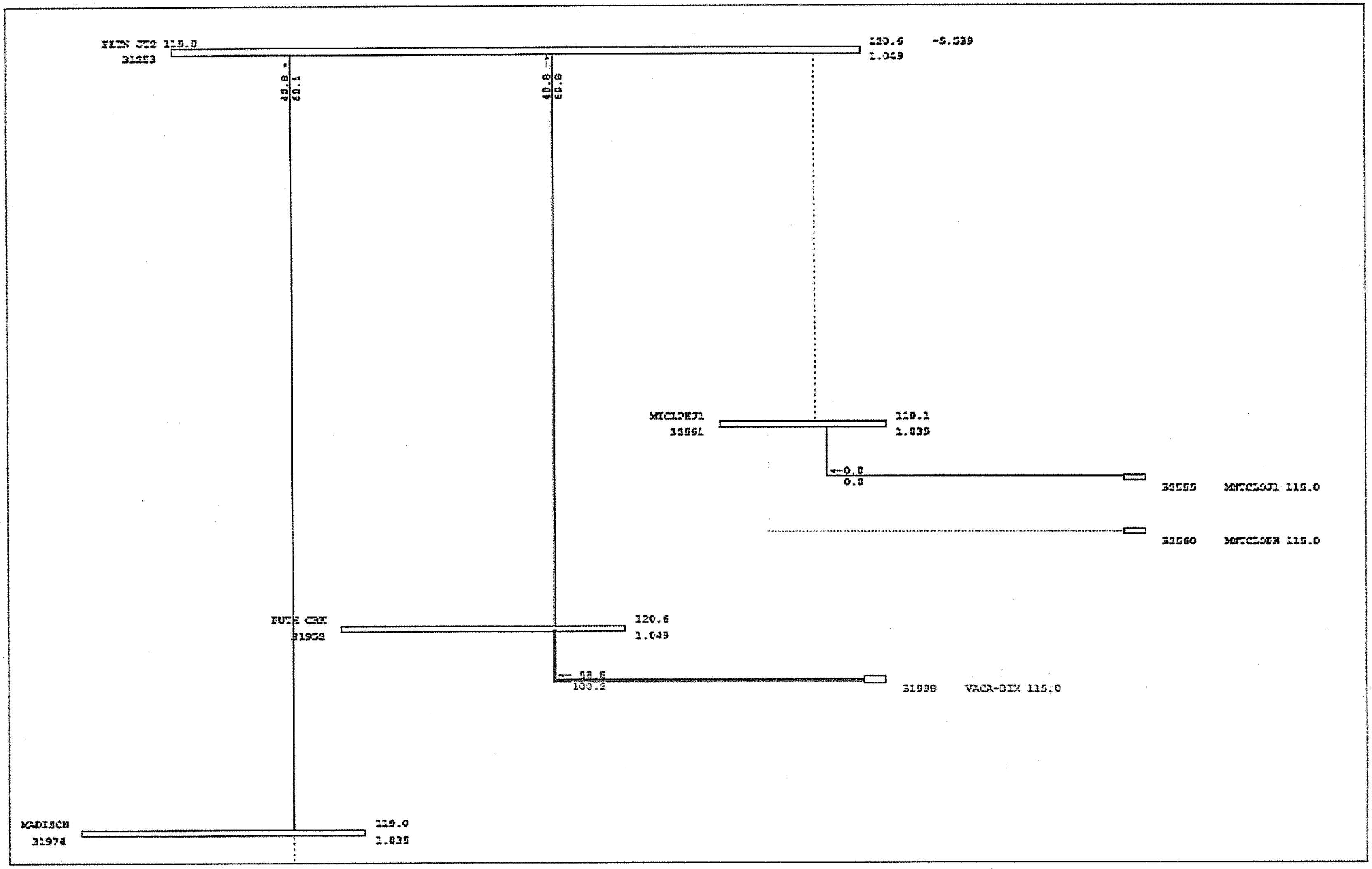


Figure 2: WECC 2014 Madison-VACA 115 kV Flows

It was determined that approximately 3MW of battery storage would be required to keep Madison-Vaca 115kV line below its normal. 3MW of storage would be installed in 2014, and this is would be sufficient to keep the limiting element below 100% of its normal rating until 2019. In 2019 additional battery storage will be installed to meet load levels for the next five years. This cycle will continue until enough batter storage is installed to cover a 30 year project life.

To avoid the line overload a 3MW battery storage device was placed at the PUTH CRK 115kV substation. Table 2 below shows the assumed 2019 load (5 year). Figure 3 shows the line flows after a storage device placed at the PUTH CRK 115kV substation.

Station Name	Assumed 2014 Load (MW/MVAR)	5 year
PUTH CRK	18	19.2
MADISON	38.6	41.2
Total Load	56.6	60.4
Required Battery		3

Table 2 Projected Madison – VACA Pocket 2019 Load

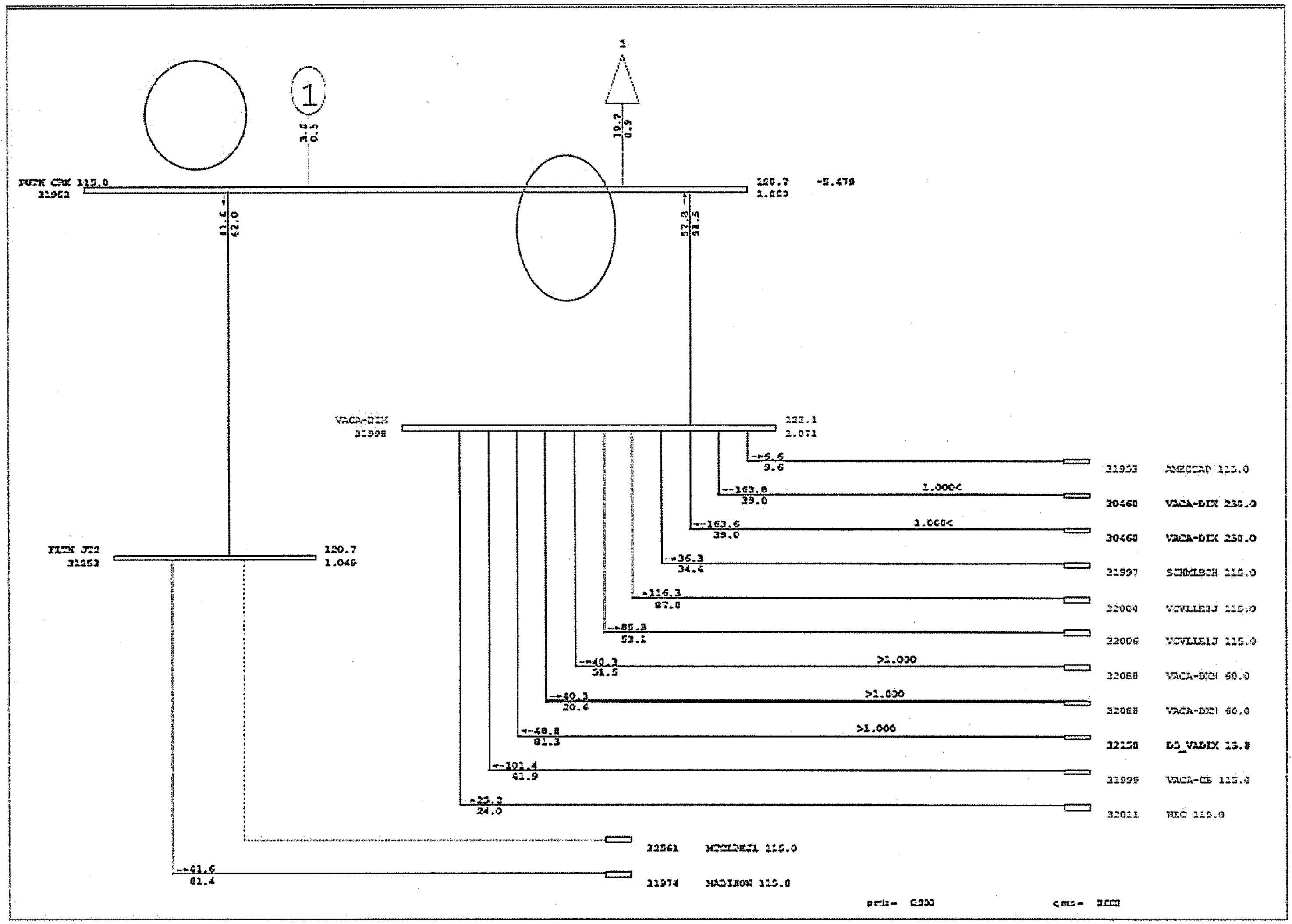


Figure 3: Madison- Vaca 115 kV Pocket 2019 (5 Year Projection)

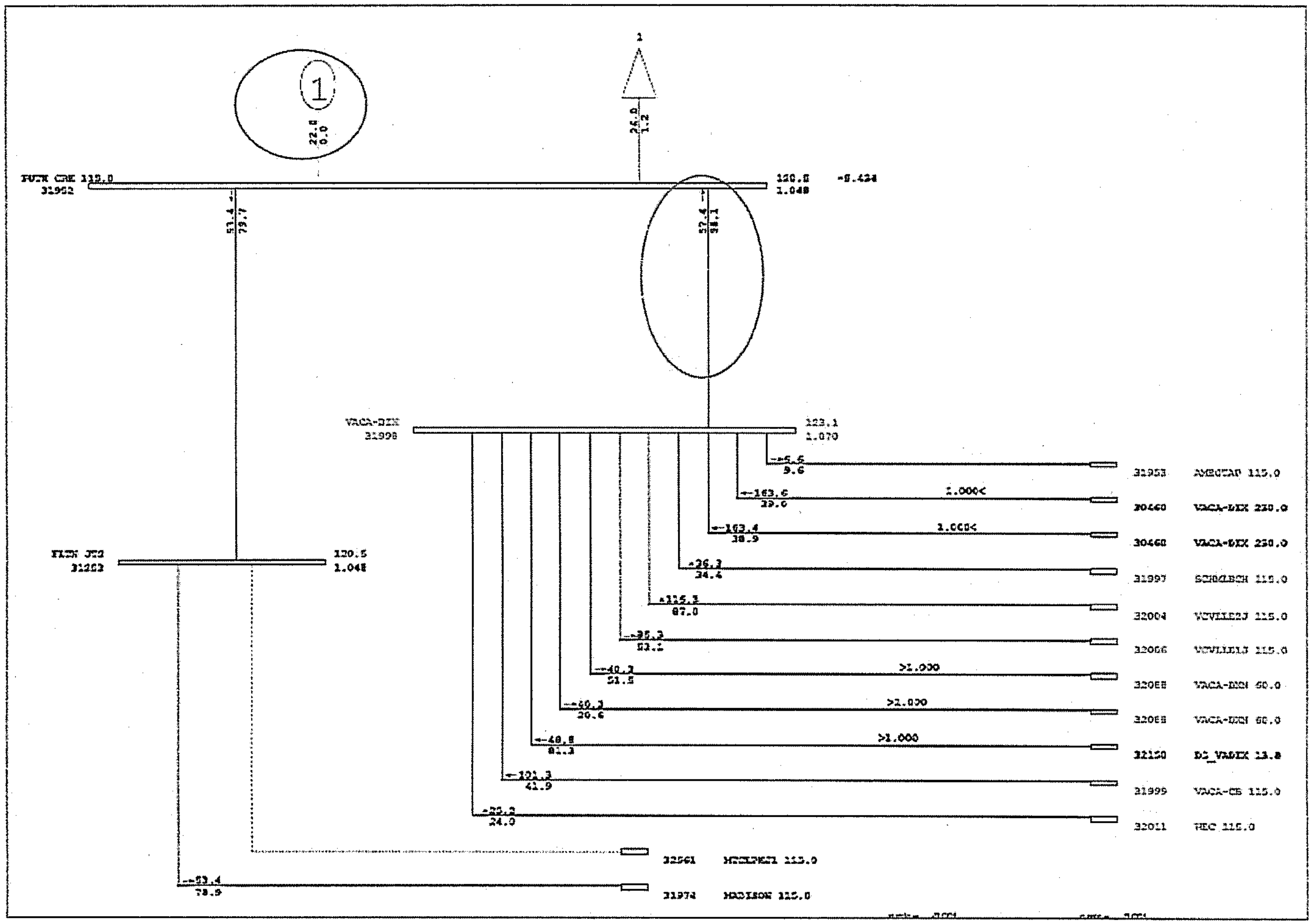


Figure 4: Madison-Vaca 115 kV Pocket 2044 (30 Year) Projection

The next step involved calculating the required battery size for a 30 year load growth. The Madison-Vaca 115kV load was increased at a rate of 3% per year. This rate was found in the CEC Staff Final Energy Demand Forecast Report. In the report the CEC states that 1.3% is the forecasted average annual growth in load from 2008-2020 as shown below in table 3.

Business-as-Usual Reference Case						
Source: CEC Staff Final Energy Demand Forecast Report, October 2007						
Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	21,886	1.3%	81,532	95,598	1.3%
SCE	21,476	25,777	1.5%	87,966	106,018	1.6%
SDG&E	3,712	4,423	1.5%	18,687	22,651	1.6%
SMUD	3,174	3,741	1.4%	11,887	13,990	1.4%
LADWP	5,717	6,010	0.4%	28,004	29,592	0.5%
NorCalMunis	5,077	5,942	1.3%	35,720	39,440	0.8%
SoCalMunis	5,079	5,959	1.3%	35,148	38,276	0.7%
California	62,946	73,738	1.3%	298,945	345,566	1.2%

Table 3: CEC Energy Demand Forecast

It was found that a 22MW battery storage device at the PUTH CRK 115kV substation was required to keep limiting element below its normal rating. The 2044 (30 year) Madison-Vaca 115kV load values are in table 4 below, along with the required battery storage sizes to accommodate the load growth.

Station Name	Assumed 2014 Load (MW/MVAR)	5 year	10 Year	15 year	20 year	25 year	2044 Expected Values (30 Year)
PUTH CRK	18	19.2	20.5	21.8	23.3	24.9	26.5
MADISON	38.6	41.2	43.9	46.9	50.0	53.3	56.9
Total Load	56.6	60.4	64.4	68.7	73.3	78.2	83.4
Required Battery		3	6	9	13	17	22.0

Table 4: Projected 30 Year Storage Device Size

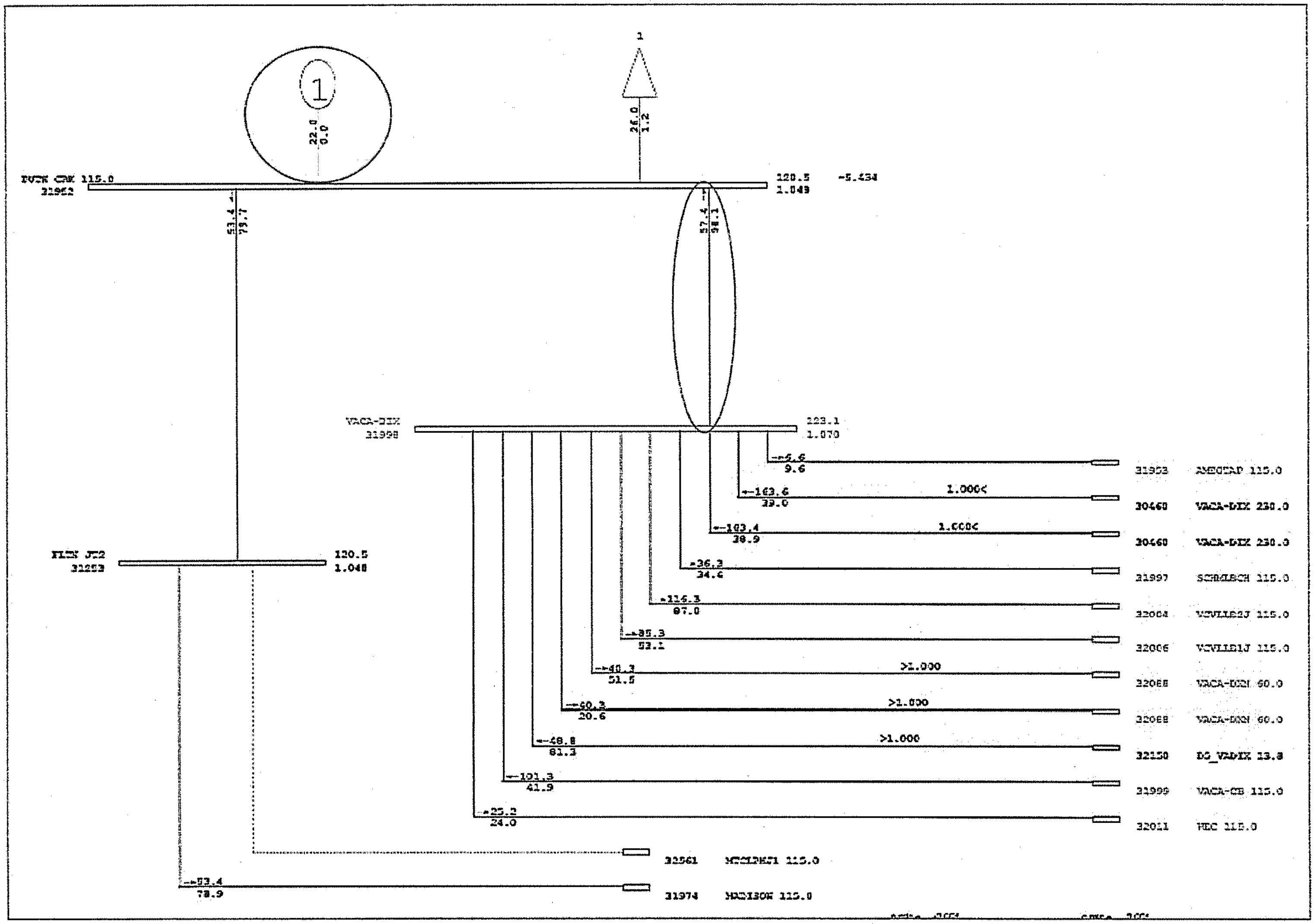


Figure 5: Madison-Vaca 115 kV Pocket 2044 (30 Year) Projection

Economic Analysis

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

WGD proposes using a service life of 30 years..Table 5 below shows the WGD ratemaking assumptions.

Install Date	Assumption	Value	Pre-Calculations	Note
	Battery Cost ($/MW)	$1,500,000.00		
Year 1	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$4,500,000.0	-	3MW*$1.2M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$150,000.00	
Year 5	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$4,437,637.3	-	(6-3)MW*$1.2M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$147,921.24	
Year 10	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$5,009,698.3	-	(9-6)MW*$1.2M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$166,989.94	
Year 15	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$5,638,336.5	-	(13-9)MW*$1.2M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$187,944.55	
Year 20	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$6,328,554.4	-	(17-13)MW*$1.2M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$210,951.81	
Year 25	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$7,085,773.5	-	(22-17)MW*$1.2M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$236,192.45	
	O&M = Operations and Maintanance	17.9%	-	
	A&G = Administrative and General	7.30%	-	
	Cost of Capital	9.27%	-	
	Taxes	22.4%	-	
	i = Interest Rate	7.00%	-	

Table 5: WGD Ratemaking Assumptions

Assumption	Value	Pre-Calculations
n = Asset Life (Years)	30	-
Salvage Value ($)	$0.0	-
Capital Cost ($)	$14,000,000.0	-
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$466,666.67
O&M = Operations and Maintanance	17.9%	-
A&G = Administrative and General	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 6: Proposed Project Ratemaking Assumptions

Using the assumptions listed above, the WGD solution has a levelized annual revenue requirement of $5.7M compared to $5.8M for the recommended Reconductor project. The overall project cost was calculated at $70.2M NPV compared to $72.5M NPV for recommended Reconductor project with an additional $5.3M in Power Quality and Reliability services. The recommended Reconductor project to WGD cost ratio is 1.11% indicating a large economic benefit as the WGD project is 11% less expensive than the recommended Reconductor project proposed solution.

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Power Quality & Reliability Services	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 4,500,000	$ 150,000	$ 417,150	$ 805,500	$ 328,500	$ 1,008,000	$ (153,724)	$ 2,709,150	$ 2,531,916	$ 5,658,937
1	$ 4,350,000	$ 150,000	$ 403,245	$ 778,650	$ 317,550	$ 974,400	$ (153,724)	$ 2,623,845	$ 2,291,768	
2	$ 4,200,000	$ 150,000	$ 389,340	$ 751,800	$ 306,600	$ 940,800	$ (153,724)	$ 2,538,540	$ 2,072,205	
3	$ 4,050,000	$ 150,000	$ 375,435	$ 724,950	$ 295,650	$ 907,200	$ (153,724)	$ 2,453,235	$ 1,871,561	
4	$ 3,900,000	$ 150,000	$ 361,530	$ 698,100	$ 284,700	$ 873,600	$ (153,724)	$ 2,367,930	$ 1,688,301	
5	$ 8,187,637	$ 297,921	$ 758,994	$ 1,465,587	$ 597,698	$ 1,834,031	$ (305,318)	$ 4,954,231	$ 3,301,213	
6	$ 7,889,716	$ 297,921	$ 731,377	$ 1,412,259	$ 575,949	$ 1,767,296	$ (305,318)	$ 4,784,803	$ 2,979,735	
7	$ 7,591,795	$ 297,921	$ 703,759	$ 1,358,931	$ 554,201	$ 1,700,562	$ (305,318)	$ 4,615,375	$ 2,686,190	
8	$ 7,293,874	$ 297,921	$ 676,142	$ 1,305,603	$ 532,453	$ 1,633,828	$ (305,318)	$ 4,445,947	$ 2,418,301	
9	$ 6,995,952	$ 297,921	$ 648,525	$ 1,252,275	$ 510,705	$ 1,567,093	$ (305,318)	$ 4,276,519	$ 2,173,966	
10	$ 11,707,729	$ 464,911	$ 1,085,307	$ 2,095,684	$ 854,664	$ 2,622,531	$ (476,454)	$ 7,123,097	$ 3,384,132	
11	$ 11,242,818	$ 464,911	$ 1,042,209	$ 2,012,464	$ 820,726	$ 2,518,391	$ (476,454)	$ 6,858,702	$ 3,045,346	
12	$ 10,777,907	$ 464,911	$ 999,112	$ 1,929,245	$ 786,787	$ 2,414,251	$ (476,454)	$ 6,594,307	$ 2,736,403	
13	$ 10,312,996	$ 464,911	$ 956,015	$ 1,846,026	$ 752,849	$ 2,310,111	$ (476,454)	$ 6,329,912	$ 2,454,849	
14	$ 9,848,085	$ 464,911	$ 912,917	$ 1,762,807	$ 718,910	$ 2,205,971	$ (476,454)	$ 6,065,517	$ 2,198,422	
15	$ 15,021,510	$ 652,856	$ 1,392,494	$ 2,688,850	$ 1,096,570	$ 3,364,818	$ (669,065)	$ 9,195,588	$ 3,114,864	
16	$ 14,368,654	$ 652,856	$ 1,331,974	$ 2,571,989	$ 1,048,912	$ 3,218,579	$ (669,065)	$ 8,824,309	$ 2,793,550	
17	$ 13,715,798	$ 652,856	$ 1,271,455	$ 2,455,128	$ 1,001,253	$ 3,072,339	$ (669,065)	$ 8,453,030	$ 2,500,947	
18	$ 13,062,943	$ 652,856	$ 1,210,935	$ 2,338,267	$ 953,595	$ 2,926,099	$ (669,065)	$ 8,081,751	$ 2,234,672	
19	$ 12,410,087	$ 652,856	$ 1,150,415	$ 2,221,406	$ 905,936	$ 2,779,859	$ (669,065)	$ 7,710,472	$ 1,992,533	
20	$ 18,085,786	$ 863,808	$ 1,676,552	$ 3,237,356	$ 1,320,262	$ 4,051,216	$ (885,255)	$ 11,149,194	$ 2,692,676	
21	$ 17,221,978	$ 863,808	$ 1,596,477	$ 3,082,734	$ 1,257,204	$ 3,857,723	$ (885,255)	$ 10,657,947	$ 2,405,639	
22	$ 16,358,171	$ 863,808	$ 1,516,402	$ 2,928,113	$ 1,194,146	$ 3,664,230	$ (885,255)	$ 10,166,699	$ 2,144,634	
23	$ 15,494,363	$ 863,808	$ 1,436,327	$ 2,773,491	$ 1,131,089	$ 3,470,737	$ (885,255)	$ 9,675,452	$ 1,907,483	
24	$ 14,630,555	$ 863,808	$ 1,356,252	$ 2,618,869	$ 1,068,031	$ 3,277,244	$ (885,255)	$ 9,184,204	$ 1,692,182	
25	$ 20,852,521	$ 1,100,000	$ 1,933,029	$ 3,732,601	$ 1,522,234	$ 4,670,965	$ (1,127,312)	$ 12,958,829	$ 2,231,452	
26	$ 19,752,521	$ 1,100,000	$ 1,831,059	$ 3,535,701	$ 1,441,934	$ 4,424,565	$ (1,127,312)	$ 12,333,259	$ 1,984,796	
27	$ 18,652,521	$ 1,100,000	$ 1,729,089	$ 3,338,801	$ 1,361,634	$ 4,178,165	$ (1,127,312)	$ 11,707,689	$ 1,760,862	
28	$ 17,552,521	$ 1,100,000	$ 1,627,119	$ 3,141,901	$ 1,281,334	$ 3,931,765	$ (1,127,312)	$ 11,082,119	$ 1,557,734	
29	$ 16,452,521	$ 1,100,000	$ 1,525,149	$ 2,945,001	$ 1,201,034	$ 3,685,365	$ (1,127,312)	$ 10,456,549	$ 1,373,647	
TOTAL	$ 356,480,962	$ 17,647,479	$ 33,045,785	$ 63,810,092	$ 26,023,110	$ 79,851,735	$ (18,085,644)	$ 220,378,202	$ 70,221,976	

Table 7: WGD Cost Estimate

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 14,000,000	$ 466,667	$ 1,297,800	$ 2,506,000	$ 1,022,000	$ 3,136,000	$ 8,428,467	$ 7,877,072	$ 5,841,231
1	$ 13,533,333	$ 466,667	$ 1,254,540	$ 2,422,467	$ 987,933	$ 3,031,467	$ 8,163,073	$ 7,129,944	
2	$ 13,066,667	$ 466,667	$ 1,211,280	$ 2,338,933	$ 953,867	$ 2,926,933	$ 7,897,680	$ 6,446,859	
3	$ 12,600,000	$ 466,667	$ 1,168,020	$ 2,255,400	$ 919,800	$ 2,822,400	$ 7,632,287	$ 5,822,635	
4	$ 12,133,333	$ 466,667	$ 1,124,760	$ 2,171,867	$ 885,733	$ 2,717,867	$ 7,366,893	$ 5,252,493	
5	$ 11,666,667	$ 466,667	$ 1,081,500	$ 2,088,333	$ 851,667	$ 2,613,333	$ 7,101,500	$ 4,732,029	
6	$ 11,200,000	$ 466,667	$ 1,038,240	$ 2,004,800	$ 817,600	$ 2,508,800	$ 6,836,107	$ 4,257,184	
7	$ 10,733,333	$ 466,667	$ 994,980	$ 1,921,267	$ 783,533	$ 2,404,267	$ 6,570,713	$ 3,824,215	
8	$ 10,266,667	$ 466,667	$ 951,720	$ 1,837,733	$ 749,467	$ 2,299,733	$ 6,305,320	$ 3,429,676	
9	$ 9,800,000	$ 466,667	$ 908,460	$ 1,754,200	$ 715,400	$ 2,195,200	$ 6,039,927	$ 3,070,392	
10	$ 9,333,333	$ 466,667	$ 865,200	$ 1,670,667	$ 681,333	$ 2,090,667	$ 5,774,533	$ 2,743,439	
11	$ 8,866,667	$ 466,667	$ 821,940	$ 1,587,133	$ 647,267	$ 1,986,133	$ 5,509,140	$ 2,446,124	
12	$ 8,400,000	$ 466,667	$ 778,680	$ 1,503,600	$ 613,200	$ 1,881,600	$ 5,243,747	$ 2,175,968	
13	$ 7,933,333	$ 466,667	$ 735,420	$ 1,420,067	$ 579,133	$ 1,777,067	$ 4,978,353	$ 1,930,691	
14	$ 7,466,667	$ 466,667	$ 692,160	$ 1,336,533	$ 545,067	$ 1,672,533	$ 4,712,960	$ 1,708,194	
15	$ 7,000,000	$ 466,667	$ 648,900	$ 1,253,000	$ 511,000	$ 1,568,000	$ 4,447,567	$ 1,506,545	
16	$ 6,533,333	$ 466,667	$ 605,640	$ 1,169,467	$ 476,933	$ 1,463,467	$ 4,182,173	$ 1,323,969	
17	$ 6,066,667	$ 466,667	$ 562,380	$ 1,085,933	$ 442,867	$ 1,358,933	$ 3,916,780	$ 1,158,834	
18	$ 5,600,000	$ 466,667	$ 519,120	$ 1,002,400	$ 408,800	$ 1,254,400	$ 3,651,387	$ 1,009,639	
19	$ 5,133,333	$ 466,667	$ 475,860	$ 918,867	$ 374,733	$ 1,149,867	$ 3,385,993	$ 875,006	
20	$ 4,666,667	$ 466,667	$ 432,600	$ 835,333	$ 340,667	$ 1,045,333	$ 3,120,600	$ 753,666	
21	$ 4,200,000	$ 466,667	$ 389,340	$ 751,800	$ 306,600	$ 940,800	$ 2,855,207	$ 644,458	
22	$ 3,733,333	$ 466,667	$ 346,080	$ 668,267	$ 272,533	$ 836,267	$ 2,589,813	$ 546,313	
23	$ 3,266,667	$ 466,667	$ 302,820	$ 584,733	$ 238,467	$ 731,733	$ 2,324,420	$ 458,252	
24	$ 2,800,000	$ 466,667	$ 259,560	$ 501,200	$ 204,400	$ 627,200	$ 2,059,027	$ 379,374	
25	$ 2,333,333	$ 466,667	$ 216,300	$ 417,667	$ 170,333	$ 522,667	$ 1,793,633	$ 308,856	
26	$ 1,866,667	$ 466,667	$ 173,040	$ 334,133	$ 136,267	$ 418,133	$ 1,528,240	$ 245,940	
27	$ 1,400,000	$ 466,667	$ 129,780	$ 250,600	$ 102,200	$ 313,600	$ 1,262,847	$ 189,935	
28	$ 933,333	$ 466,667	$ 86,520	$ 167,067	$ 68,133	$ 209,067	$ 997,453	$ 140,205	
29	$ 466,667	$ 466,667	$ 43,260	$ 83,533	$ 34,067	$ 104,533	$ 732,060	$ 96,169	
TOTAL	$ 217,000,000	$ 14,000,000	$ 20,115,900	$ 38,843,000	$ 15,841,000	$ 48,608,000	$ 137,407,900	$ 72,484,074	

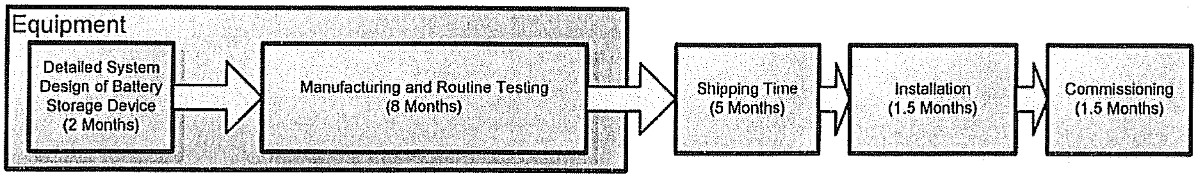
Table 8: Proposed Project Cost Estimate

Power Quality & Reliability Services	PV	
$ (153,724)	0.934579439	$ (143,667.58)
$ (153,724)	0.873438728	$ (134,268.77)
$ (153,724)	0.816297877	$ (125,484.83)
$ (153,724)	0.762895212	$ (117,275.54)
$ (153,724)	0.712986179	$ (109,603.31)
$ (305,318)	0.666342224	$ (203,446.45)
$ (305,318)	0.622749742	$ (190,136.87)
$ (305,318)	0.582009105	$ (177,698.01)
$ (305,318)	0.543933743	$ (166,072.90)
$ (305,318)	0.508349292	$ (155,208.32)
$ (476,454)	0.475092796	$ (226,360.03)
$ (476,454)	0.444011959	$ (211,551.43)
$ (476,454)	0.414964448	$ (197,711.62)
$ (476,454)	0.387817241	$ (184,777.22)
$ (476,454)	0.36244602	$ (172,688.99)
$ (669,065)	0.338734598	$ (226,635.58)
$ (669,065)	0.31657439	$ (211,808.95)
$ (669,065)	0.295863916	$ (197,952.29)
$ (669,065)	0.276508333	$ (185,002.14)
$ (669,065)	0.258419003	$ (172,899.20)
$ (885,255)	0.241513087	$ (213,800.63)
$ (885,255)	0.225713165	$ (199,813.67)
$ (885,255)	0.210946883	$ (186,741.75)
$ (885,255)	0.19714662	$ (174,525.00)
$ (885,255)	0.184249178	$ (163,107.47)
$ (1,127,312)	0.172195493	$ (194,117.98)
$ (1,127,312)	0.160930367	$ (181,418.68)
$ (1,127,312)	0.150402212	$ (169,550.17)
$ (1,127,312)	0.140562815	$ (158,458.10)
$ (1,127,312)	0.131367117	$ (148,091.68)
	TOTAL	$ (5,299,875)

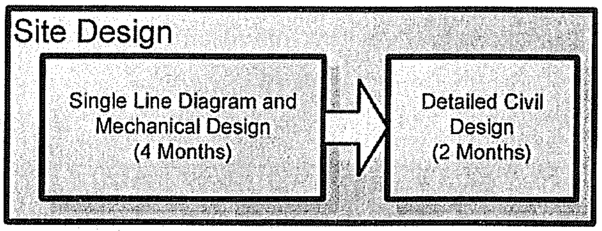
Table 9: Power Quality & Reliability Service Benefit

Construction schedule and expected online date:

The chart below outlines the estimated schedule of 18 months



During the 10 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Technical Data

The following pieces of technical information are attached to this application:

- Network model for power flow study in GE-PSLF format
    - madison.epc
- GE PSLF Batt model and model parameters
    - PSLF_batt_Model.pdf
    - BATT_epcl_parameters.xls
- Sample one line diagram
    - NAS Battery System SLD.pdf

Miscellaneous Data

Proposed entity to construct, own, and finance the project

Western Grid Development, LLC (WGD) will own the storage device project and will act as project manager during construction. WGD will also be responsible for financing the project.

Planned operator of the project

WGD will file to become a PTO under the CAISO tariff and will operate the project upon completion.

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the attachment A (technical data) to the CAISO contact listed in section 3. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to be considered in the CAISO Transmission Plan. This submission is for (check one)[1]:

- ☒ Reliability Transmission Project (refer to section 1 of attachment A)
- ☐ Merchant Transmission Facility (refer to section 1 of attachment A)
- ☐ Economic Transmission Project (refer to section 1 of attachment A)
- ☐ Location Constrained Resource Interconnection Facility (LCRIF) (refer to sections 1 & 2 of attachment A)
- ☐ Project to preserve Long-term Congestion Revenue Rights (CRR) (refer to section 1 of attachment A)
- ☐ Economic Planning Study Request (refer to section 3 of attachment A)
- ☐ Others (refer to section 4 of attachment A)

2. For the submission of a Reliability, Merchant, Economic, LCRIF, and CRR project, the project sponsor is

- ☒ Seeking ISO approval in this planning cycle
- ☐ Submitting for information only (not requiring ISO approval in this planning cycle)

3. Please provide the following basic information about this submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Weedpatch 70kV Energy Storage Project**

Submission Date: **November 30, 2009**

b. Project locations or the proposed interconnection point(s) :

PG&E's Weedpatch 70kV Substation

c. Project capacity (Net MW):

Initially 3MW of energy storage will be installed at the Weedpatch 70kV substation. Additional storage will be added every 5 years to maintain system reliability and account for load growth. The table below outlines the amount of storage that is required from years 1-30.

[1] Please contact the ISO staff at requestwindow@caiso.com for any questions regarding the definitions of these submission categories in this form to the ISO

Weedpatch	
Year	Storage Device Size (MW)
5	3
10	5
15	8
20	11
25	14
30	18

Table 1: Required Storage Device Size

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project e.g. overall scope, objectives etc.

The CAISO Reliability Assessment Results (September 15, 2009) for the Kern area identified that loss of the Wheeler-Weedpatch 70kV line while Kern Canyon generation is offline will cause an emergency overload on the line between San Bernard and Stalin Jct. 70kV. It was identified in the CAISO studies that the overload will reach 100% of its emergency rating by 2014. The CAISO recommends a re-conductor of the line.

WGD is proposing a alternative solution which includes installing a 3MW battery storage device at the Weedpatch 70kV substation in 2014, followed by six additional battery storage installations (one every 5 years) to account for load growth. This project will resolve reliability concerns for 30 years.

Economic analysis indicates that the WGD solution has a levelized annual revenue requirement of $4.9M compared to $5.0M for the recommended Reconductor project. The overall project cost was calculated at $60.4M NPV compared to $62.1M NPV for recommended Reconductor project with an additional $6.5M in Power Quality and Reliability services. The recommended Reconductor project to WGD cost ratio is 1.14% indicating a large economic benefit as the WGD project is 14% less expensive than the recommended Reconductor project proposed solution.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date: **03 / 30 / 2014**

Proposed Trial Operation date: **03 / 30 / 2014**

Proposed Commercial Operation date: **03 / 30 / 2014**

Proposed Term of Service: **30 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title: **Managing Member**

Company Name: **Western Grid Development, LLC**

General Data

Description of Project

Please see the attached report which includes a full reliability analysis and economic analysis on all WGD proposed projects.

The CAISO Reliability Assessment Results (September 15, 2009) for the Kern area identified that loss of the Wheeler-Weedpatch 70kV line while Kern Canyon generation is offline will cause an emergency overload on the line between San Bernard and Stalin Jct. 70kV. It was identified in the CAISO studies that the overload will reach 100% of its emergency rating by 2014. The CAISO recommends a re-conductor of the line.

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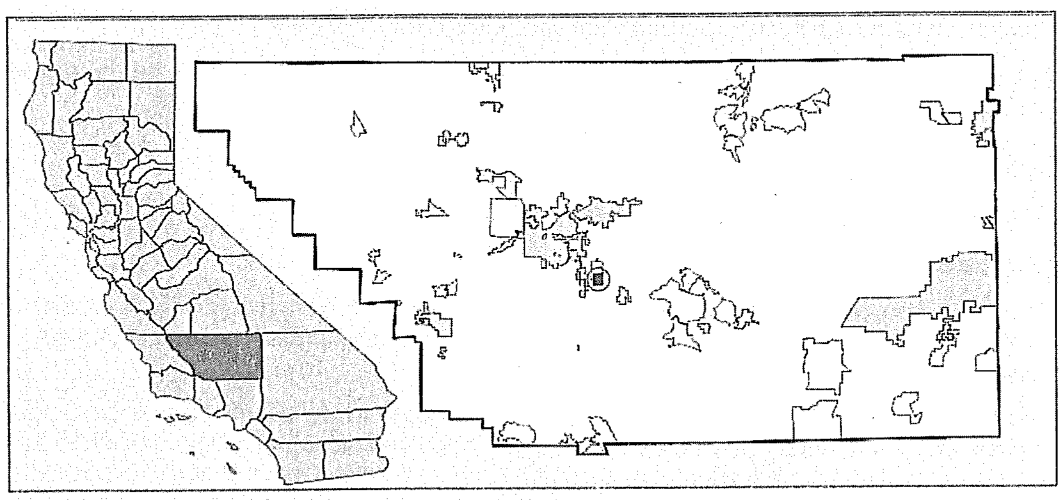


Figure 1: Weedpatch Geographical Location

Required Storage Device Size

A load flow study was performed using the WECC 2015 heavy summer base case. The WECC 2015 heavy summer base case was tuned to 2014 load values which according to CAISO studies would put the limiting element at 100% of its emergency rating by 2014. The tuned results can be seen in Figure 2 below.

2. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets applicable reliability requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

3. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives, must be provided to CAISO by the closing date of Request Window.

4. Submission under "Other" category

This category of submission includes other type of proposals that may be considered as alternatives in the transmission planning process such as generation, demand response programs, new technologies etc. However, the ISO encourages project sponsors to contact CAISO staff prior to submitting these proposals through the Request Window.

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

This section applies to all transmission project submissions. It does not apply to Economic Planning Study Requests.

Any transmission project, including those seeking cost recovery through Long-term Congestion Revenue Rights, whether submitted by a PTO, non-PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[2]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route

Technical Data

- Network model for power flow study in GE-PSLF format. In some cases, Dynamic models for stability study in GE-PSLF format may also be required

Planning Level Cost Data[3]

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[2] This appendix lists the minimum amount of data required by the ISO for the first screening purposes. Additional data may be requested by the ISO later during the course of project evaluation

[3] Not required for Merchant Transmission Facilities

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
CAISO TRANSMISSION PLANNING PROCESS
REQUEST WINDOW SUBMISSION FORM

Street Address:	200 East 94th Street, Suite 2218
City, State:	New York, NY
Zip Code:	10128
Phone Number:	917-282-0658
Fax Number:	212-937-4622
Email Address:	dizard@gmail.com

g. Technical Data (set forth in Attachment A)

☒ Is attached to this Request
☐ Will be provided at a later date

4. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Young
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

5. This Request is submitted by: Western Grid Development, LLC

Name of the Customer:	Western Grid Development, LLC
By (signature):	(John Dizard)
Name (type or print):	John Dizard
Title:	Managing Member
Company Name:	Western Grid Development, LLC
Street Address:	200 East 94th Street, Suite 2218
City, State:	New York, NY
Zip Code:	10128
Phone Number:	212-937-4622
Email Address:	dizard@gmail.com
Date:	November 30, 2009

Economic Analysis

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

WGD proposes using a service life of 30 years. Table 5 below shows the WGD ratemaking assumptions. For comparative purposes, these assumptions will match those listed by PG&E as shown in table 6.

	Assumption	Value	Pre-Calculation	Note
	Battery Cost ($/MW)	$1,500,000.00		
Year 1	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$4,500,000.0	-	3MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$150,000.00	
Year 5	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$3,510,811.9	-	(5-3)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$117,027.06	
Year 10	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$3,959,212.0	-	(8-5)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$131,973.73	
Year 15	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$4,451,814.7	-	(11-8)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$148,393.82	
Year 20	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$4,992,521.9	-	(14-11)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$166,417.40	
Year 25	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$5,585,639.4	-	(18-14)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$186,187.98	
	O&M = Operations and Maintanance	17.9%	-	
	A&G = Administrative and General	7.30%	-	
	Cost of Capital	9.27%	-	
	Taxes	22.4%	-	
	i = Interest Rate	7.00%	-	

Table 5: WGD Ratemaking Assumptions

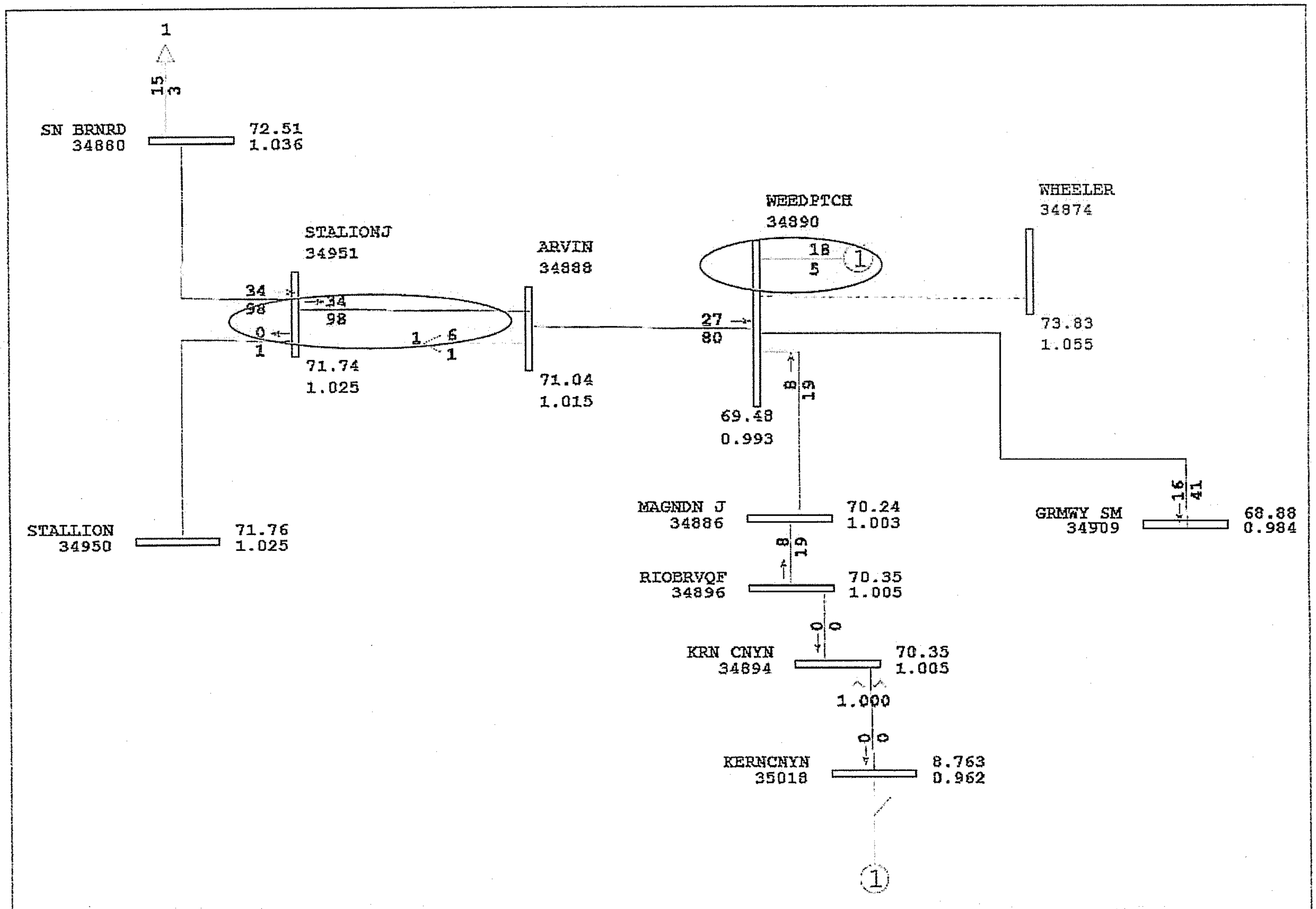


Figure 4: Weedpatch 70kV Pocket 2044 (30 Year) Projection

The next step involved calculating the required battery size for a 30 year load growth. The Kern load was increased at a rate of 3% per year. This rate was found in the CEC Staff Final Energy Demand Forecast Report. In the report the CEC states that 1.3% is the forecasted average annual growth in load from 2008-2020 as shown below in table 3.

Business-as-Usual Reference Case						
Source: CEC Staff Final Energy Demand Forecast Report, October 2007						
Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	21,886	1.3%	81,532	95,598	1.3%
SCE	21,476	25,777	1.5%	87,966	106,018	1.6%
SDG&E	3,712	4,423	1.5%	18,687	22,651	1.6%
SMUD	3,174	3,741	1.4%	11,887	13,990	1.4%
LADWP	5,717	6,010	0.4%	28,004	29,592	0.5%
NorCalMunis	5,077	5,942	1.3%	35,720	39,440	0.8%
SoCalMunis	5,079	5,959	1.3%	35,148	38,276	0.7%
California	62,946	73,738	1.3%	298,945	345,566	1.2%

Table 3: CEC Energy Demand Forecast

It was found that an 18MW battery storage device at the Weedpatch 70kV substation was required to keep limiting element below its emergency rating. The 2044 (30 year) Kern load values are in table 4 below, along with the required battery storage sizes to accommodate the load growth.

Zone Number	Assumed 2014 Load (MW/MVAR)	5 year	10 Year	15 year	20 year	25 year	2044 Expected Values (30 Year)
315 - Conforming Load Kern	1150	1226.7	1308.6	1395.9	1489.0	1588.3	1694.3
	233.5	249.1	265.7	283.4	302.3	322.5	344.0
Total Load	1150.0	1226.7	1308.6	1395.9	1489.0	1588.3	1694.3
Required Battery		3	5	8	11	14	18.0

Table 4: Projected 30 Year Storage Device Size

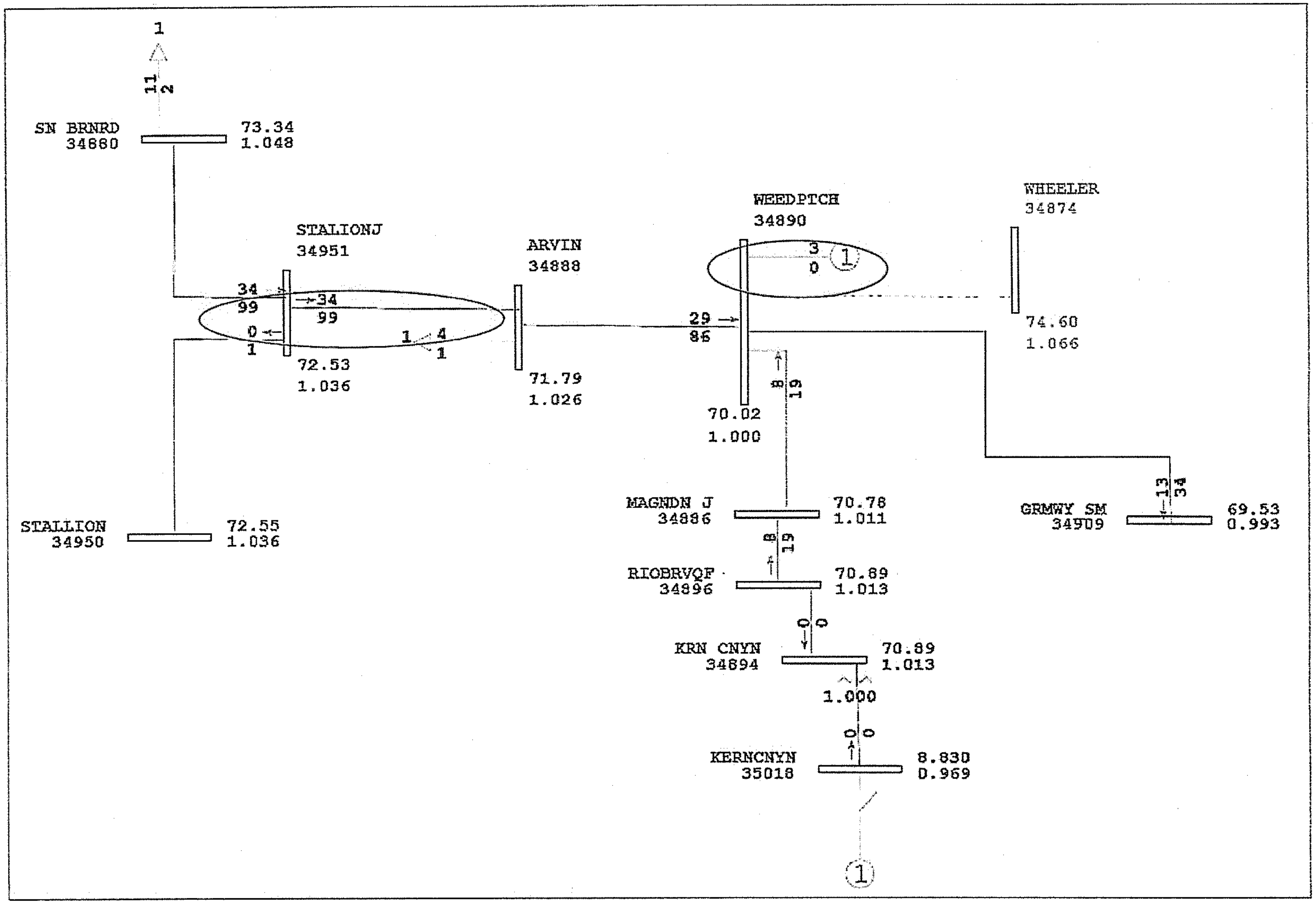


Figure 3: Weedpatch 70 kV Pocket 2019 (5 Year) Projection

It was determined that approximately 3MW of battery storage would be required to keep post contingency line flows on the San Bernard-Stalion Jct 70kV line segment below its emergency rating for the loss of the Wheeler-Weedpatch 70kV line when Kern Canyon generation is offline. 3MW of storage would be installed in 2014, and this would be sufficient to keep the limiting element below 100% of its emergency rating until 2019. In 2019 additional battery storage will be installed to meet load levels for the next five years. This cycle will continue until enough batter storage is installed to cover a 30 year project life.

To avoid the line overload a 3MW battery storage device was placed at the Weedpatch 70kV substation. Table 2 below shows the assumed 2019 load (5 year). Figure 3 shows the post contingency line flows after a storage device placed at the Weedpatch 70kV substation.

Zone Number	Assumed 2014 Load (MW/MVAR)	5 year
315 - Conforming Load Kern	1150	1226.7
	233.5	249.1
Total Load	1150.0	1226.7
Required Battery		3

Table 2: Projected Kern 2019 Load

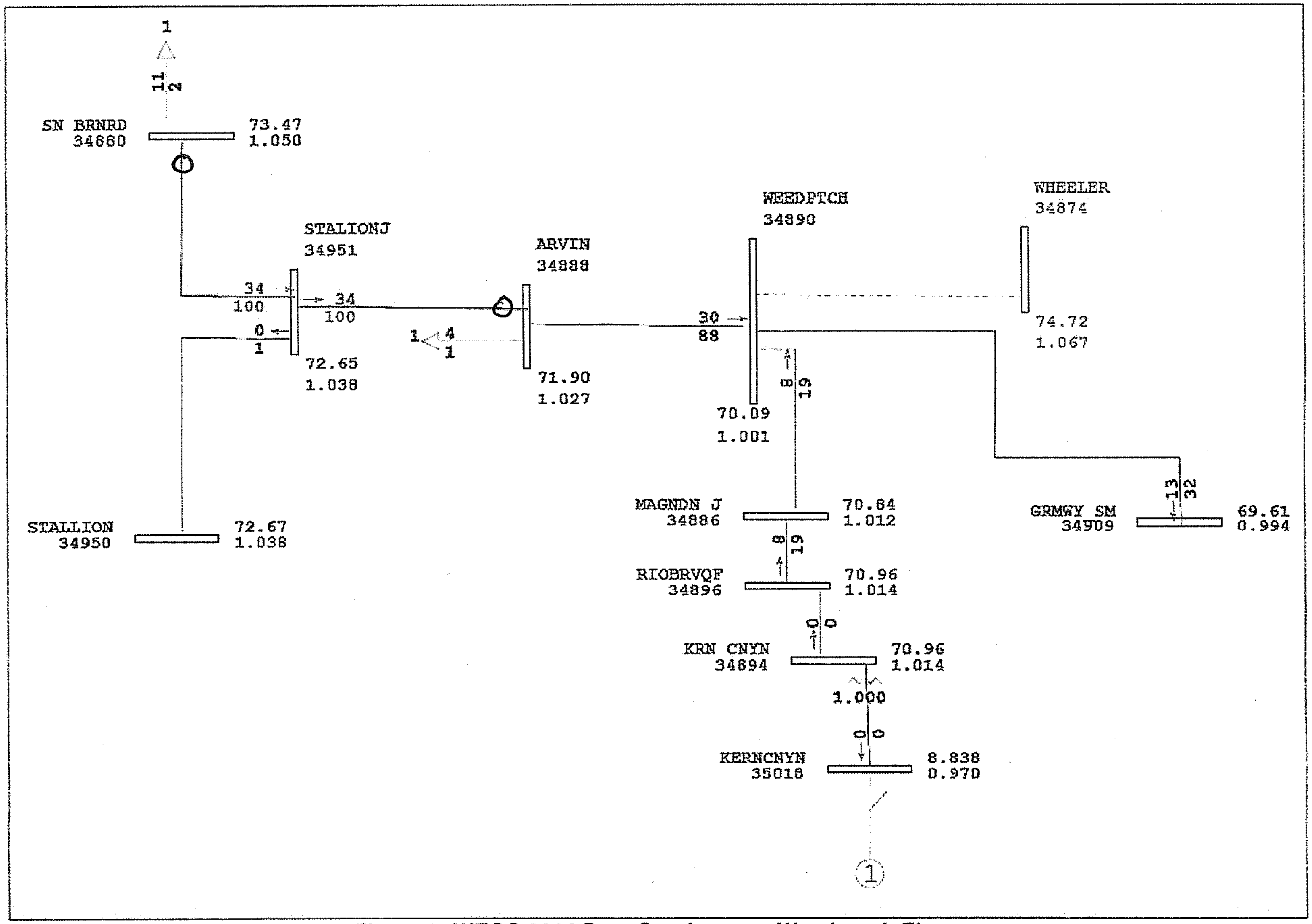


Figure 2: WECC 2014 Post Contingency Weedpatch Flows

Assumption	Value	Pre-Calculations	Note
n = Asset Life (Years)	30	-	
Salvage Value ($)	$0.0	-	
Capital Cost ($)	$12,000,000.0	-	Assume Reconductor Project will cost PG&E $12M
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$400,000.00	
O&M = Operations and Maintanance	17.9%	-	
A&G = Administrative and General	7.30%	-	
Cost of Capital	9.27%	-	
Taxes	22.4%	-	
i = Interest Rate	7.00%	-	

Table 6: PG&E Ratemaking Assumptions

Using the assumptions listed above, the WGD solution has a levelized annual revenue requirement of $4.9M compared to $5.0M for the recommended Reconductor project. The overall project cost was calculated at $60.4M NPV compared to $62.1M NPV for recommended Reconductor project with an additional $6.5M in Power Quality and Reliability services. The recommended Reconductor project to WGD cost ratio is 1.14% indicating a large economic benefit as the WGD project is 14% less expensive than the recommended Reconductor project proposed solution.

Year (n)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Power Quality & Reliability Services	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 4,500,000	$ 150,000	$ 417,150	$ 805,500	$ 328,500	$ 1,008,000	$ (217,166)	$ 2,709,150	$ 2,531,916	$ 4,865,360
1	$ 4,350,000	$ 150,000	$ 403,245	$ 778,650	$ 317,550	$ 974,400	$ (217,166)	$ 2,623,845	$ 2,291,768	
2	$ 4,200,000	$ 150,000	$ 389,340	$ 751,800	$ 306,600	$ 940,800	$ (217,166)	$ 2,538,540	$ 2,072,205	
3	$ 4,050,000	$ 150,000	$ 375,435	$ 724,950	$ 295,650	$ 907,200	$ (217,166)	$ 2,453,235	$ 1,871,561	
4	$ 3,900,000	$ 150,000	$ 361,530	$ 698,100	$ 284,700	$ 873,600	$ (217,166)	$ 2,367,930	$ 1,688,301	
5	$ 7,260,812	$ 267,027	$ 673,077	$ 1,299,685	$ 530,039	$ 1,626,422	$ (386,595)	$ 4,396,251	$ 2,929,408	
6	$ 6,993,785	$ 267,027	$ 648,324	$ 1,251,887	$ 510,546	$ 1,566,608	$ (386,595)	$ 4,244,393	$ 2,643,194	
7	$ 6,726,758	$ 267,027	$ 623,570	$ 1,204,090	$ 491,053	$ 1,506,794	$ (386,595)	$ 4,092,534	$ 2,381,892	
8	$ 6,459,731	$ 267,027	$ 598,817	$ 1,156,292	$ 471,560	$ 1,446,980	$ (386,595)	$ 3,940,676	$ 2,143,467	
9	$ 6,192,704	$ 267,027	$ 574,064	$ 1,108,494	$ 452,067	$ 1,387,166	$ (386,595)	$ 3,788,818	$ 1,926,043	
10	$ 9,884,889	$ 399,001	$ 916,329	$ 1,769,395	$ 721,597	$ 2,214,215	$ (577,663)	$ 6,020,537	$ 2,860,314	
11	$ 9,485,888	$ 399,001	$ 879,342	$ 1,697,974	$ 692,470	$ 2,124,839	$ (577,663)	$ 5,793,625	$ 2,572,439	
12	$ 9,086,887	$ 399,001	$ 842,354	$ 1,626,553	$ 663,343	$ 2,035,463	$ (577,663)	$ 5,566,713	$ 2,309,988	
13	$ 8,687,886	$ 399,001	$ 805,367	$ 1,555,132	$ 634,216	$ 1,946,087	$ (577,663)	$ 5,339,802	$ 2,070,867	
14	$ 8,288,885	$ 399,001	$ 768,380	$ 1,483,710	$ 605,089	$ 1,856,710	$ (577,663)	$ 5,112,890	$ 1,853,147	
15	$ 12,341,699	$ 547,395	$ 1,144,076	$ 2,209,164	$ 900,944	$ 2,764,541	$ (792,504)	$ 7,566,119	$ 2,562,906	
16	$ 11,794,305	$ 547,395	$ 1,093,332	$ 2,111,181	$ 860,984	$ 2,641,924	$ (792,504)	$ 7,254,816	$ 2,296,689	
17	$ 11,246,910	$ 547,395	$ 1,042,589	$ 2,013,197	$ 821,024	$ 2,519,308	$ (792,504)	$ 6,943,512	$ 2,054,335	
18	$ 10,699,515	$ 547,395	$ 991,845	$ 1,915,213	$ 781,065	$ 2,396,691	$ (792,504)	$ 6,632,209	$ 1,833,861	
19	$ 10,152,121	$ 547,395	$ 941,102	$ 1,817,230	$ 741,105	$ 2,274,075	$ (792,504)	$ 6,320,906	$ 1,633,442	
20	$ 14,597,248	$ 713,812	$ 1,353,165	$ 2,612,907	$ 1,065,599	$ 3,269,784	$ (1,033,438)	$ 9,015,267	$ 2,177,305	
21	$ 13,883,436	$ 713,812	$ 1,286,995	$ 2,485,135	$ 1,013,491	$ 3,109,890	$ (1,033,438)	$ 8,609,322	$ 1,943,237	
22	$ 13,169,624	$ 713,812	$ 1,220,824	$ 2,357,363	$ 961,383	$ 2,949,996	$ (1,033,438)	$ 8,203,377	$ 1,730,477	
23	$ 12,455,812	$ 713,812	$ 1,154,654	$ 2,229,590	$ 909,274	$ 2,790,102	$ (1,033,438)	$ 7,797,432	$ 1,537,237	
24	$ 11,742,000	$ 713,812	$ 1,088,483	$ 2,101,818	$ 857,166	$ 2,630,208	$ (1,033,438)	$ 7,391,487	$ 1,361,875	
25	$ 16,613,827	$ 900,000	$ 1,540,102	$ 2,973,875	$ 1,212,809	$ 3,721,497	$ (1,302,997)	$ 10,348,284	$ 1,781,928	
26	$ 15,713,827	$ 900,000	$ 1,456,672	$ 2,812,775	$ 1,147,109	$ 3,519,897	$ (1,302,997)	$ 9,836,454	$ 1,582,984	
27	$ 14,813,827	$ 900,000	$ 1,373,242	$ 2,651,675	$ 1,081,409	$ 3,318,297	$ (1,302,997)	$ 9,324,624	$ 1,402,444	
28	$ 13,913,827	$ 900,000	$ 1,289,812	$ 2,490,575	$ 1,015,709	$ 3,116,697	$ (1,302,997)	$ 8,812,794	$ 1,238,751	
29	$ 13,013,827	$ 900,000	$ 1,206,382	$ 2,329,475	$ 950,009	$ 2,915,097	$ (1,302,997)	$ 8,300,964	$ 1,090,474	
TOTAL	$ 296,220,033	$ 14,886,173	$ 27,459,597	$ 53,023,386	$ 21,624,062	$ 66,353,287	$ (21,551,813)	$ 183,346,505	$ 60,374,455	

Table 7: WGD Cost Estimate

Year (n)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 12,000,000	$ 400,000	$ 1,112,400	$ 2,148,000	$ 876,000	$ 2,688,000	$ 7,224,400	$ 6,751,776	$ 5,006,769
1	$ 11,600,000	$ 400,000	$ 1,075,320	$ 2,076,400	$ 846,800	$ 2,598,400	$ 6,996,920	$ 6,111,381	
2	$ 11,200,000	$ 400,000	$ 1,038,240	$ 2,004,800	$ 817,600	$ 2,508,800	$ 6,769,440	$ 5,525,879	
3	$ 10,800,000	$ 400,000	$ 1,001,160	$ 1,933,200	$ 788,400	$ 2,419,200	$ 6,541,960	$ 4,990,830	
4	$ 10,400,000	$ 400,000	$ 964,080	$ 1,861,600	$ 759,200	$ 2,329,600	$ 6,314,480	$ 4,502,137	
5	$ 10,000,000	$ 400,000	$ 927,000	$ 1,790,000	$ 730,000	$ 2,240,000	$ 6,087,000	$ 4,056,025	
6	$ 9,600,000	$ 400,000	$ 889,920	$ 1,718,400	$ 700,800	$ 2,150,400	$ 5,859,520	$ 3,649,015	
7	$ 9,200,000	$ 400,000	$ 852,840	$ 1,646,800	$ 671,600	$ 2,060,800	$ 5,632,040	$ 3,277,899	
8	$ 8,800,000	$ 400,000	$ 815,760	$ 1,575,200	$ 642,400	$ 1,971,200	$ 5,404,560	$ 2,939,723	
9	$ 8,400,000	$ 400,000	$ 778,680	$ 1,503,600	$ 613,200	$ 1,881,600	$ 5,177,080	$ 2,631,765	
10	$ 8,000,000	$ 400,000	$ 741,600	$ 1,432,000	$ 584,000	$ 1,792,000	$ 4,949,600	$ 2,351,519	
11	$ 7,600,000	$ 400,000	$ 704,520	$ 1,360,400	$ 554,800	$ 1,702,400	$ 4,722,120	$ 2,096,678	
12	$ 7,200,000	$ 400,000	$ 667,440	$ 1,288,800	$ 525,600	$ 1,612,800	$ 4,494,640	$ 1,865,116	
13	$ 6,800,000	$ 400,000	$ 630,360	$ 1,217,200	$ 496,400	$ 1,523,200	$ 4,267,160	$ 1,654,878	
14	$ 6,400,000	$ 400,000	$ 593,280	$ 1,145,600	$ 467,200	$ 1,433,600	$ 4,039,680	$ 1,464,166	
15	$ 6,000,000	$ 400,000	$ 556,200	$ 1,074,000	$ 438,000	$ 1,344,000	$ 3,812,200	$ 1,291,324	
16	$ 5,600,000	$ 400,000	$ 519,120	$ 1,002,400	$ 408,800	$ 1,254,400	$ 3,584,720	$ 1,134,831	
17	$ 5,200,000	$ 400,000	$ 482,040	$ 930,800	$ 379,600	$ 1,164,800	$ 3,357,240	$ 993,286	
18	$ 4,800,000	$ 400,000	$ 444,960	$ 859,200	$ 350,400	$ 1,075,200	$ 3,129,760	$ 865,405	
19	$ 4,400,000	$ 400,000	$ 407,880	$ 787,600	$ 321,200	$ 985,600	$ 2,902,280	$ 750,004	
20	$ 4,000,000	$ 400,000	$ 370,800	$ 716,000	$ 292,000	$ 896,000	$ 2,674,800	$ 645,999	
21	$ 3,600,000	$ 400,000	$ 333,720	$ 644,400	$ 262,800	$ 806,400	$ 2,447,320	$ 552,392	
22	$ 3,200,000	$ 400,000	$ 296,640	$ 572,800	$ 233,600	$ 716,800	$ 2,219,840	$ 468,268	
23	$ 2,800,000	$ 400,000	$ 259,560	$ 501,200	$ 204,400	$ 627,200	$ 1,992,360	$ 392,787	
24	$ 2,400,000	$ 400,000	$ 222,480	$ 429,600	$ 175,200	$ 537,600	$ 1,764,880	$ 325,178	
25	$ 2,000,000	$ 400,000	$ 185,400	$ 358,000	$ 146,000	$ 448,000	$ 1,537,400	$ 264,733	
26	$ 1,600,000	$ 400,000	$ 148,320	$ 286,400	$ 116,800	$ 358,400	$ 1,309,920	$ 210,806	
27	$ 1,200,000	$ 400,000	$ 111,240	$ 214,800	$ 87,600	$ 268,800	$ 1,082,440	$ 162,801	
28	$ 800,000	$ 400,000	$ 74,160	$ 143,200	$ 58,400	$ 179,200	$ 854,960	$ 120,176	
29	$ 400,000	$ 400,000	$ 37,080	$ 71,600	$ 29,200	$ 89,600	$ 627,480	$ 82,430	
TOTAL	$ 186,000,000	$ 12,000,000	$ 17,242,200	$ 33,294,000	$ 13,578,000	$ 41,664,000	$ 117,778,200	$ 62,129,207	

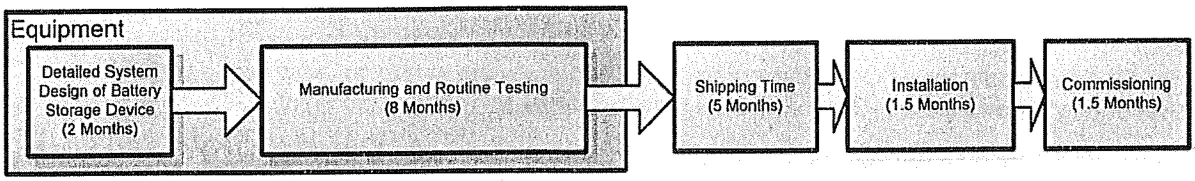
Table 8: Recommended Reconductor Project Cost Estimate

Power Quality & Reliability Services	PV	
$ (217,166)	0.934579439	$ (202,958.97)
$ (217,166)	0.873438728	$ (189,681.28)
$ (217,166)	0.816297877	$ (177,272.22)
$ (217,166)	0.762895212	$ (165,674.97)
$ (217,166)	0.712986179	$ (154,836.43)
$ (386,595)	0.666342224	$ (257,604.46)
$ (386,595)	0.622749742	$ (240,751.83)
$ (386,595)	0.582009105	$ (225,001.71)
$ (386,595)	0.543933743	$ (210,281.98)
$ (386,595)	0.508349292	$ (196,525.21)
$ (577,663)	0.475092796	$ (274,443.52)
$ (577,663)	0.444011959	$ (256,489.27)
$ (577,663)	0.414964448	$ (239,709.60)
$ (577,663)	0.387817241	$ (224,027.66)
$ (577,663)	0.36244602	$ (209,371.64)
$ (792,504)	0.338734598	$ (268,448.42)
$ (792,504)	0.31657439	$ (250,886.37)
$ (792,504)	0.295863916	$ (234,473.24)
$ (792,504)	0.276508333	$ (219,133.87)
$ (792,504)	0.258419003	$ (204,798.01)
$ (1,033,438)	0.241513087	$ (249,588.91)
$ (1,033,438)	0.225713165	$ (233,260.67)
$ (1,033,438)	0.210946883	$ (218,000.62)
$ (1,033,438)	0.19714662	$ (203,738.90)
$ (1,033,438)	0.184249178	$ (190,410.19)
$ (1,302,997)	0.172195493	$ (224,370.14)
$ (1,302,997)	0.160930367	$ (209,691.72)
$ (1,302,997)	0.150402212	$ (195,973.57)
$ (1,302,997)	0.140562815	$ (183,152.87)
$ (1,302,997)	0.131367117	$ (171,170.90)
		$ (6,481,729)

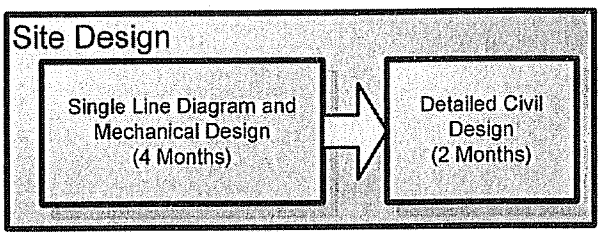
Table 9: Power Quality & Reliability Service Benefit

Construction schedule and expected online date:

The chart below outlines the estimated schedule of 18 months



During the 10 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Technical Data

The following pieces of technical information are attached to this application:

- Network model for power flow study in GE-PSLF format
  - weedpatch.epc
- GE PSLF Batt model and model parameters
  - PSLF_batt_Model.pdf
  - BATT_epcl_parameters.xls
- Sample one line diagram
  - NAS Battery System SLD.pdf

Miscellaneous Data

Proposed entity to construct, own, and finance the project

Western Grid Development, LLC (WGD) will own the storage device project and will act as project manager during construction. WGD will also be responsible for financing the project.

Planned operator of the project

WGD will file to become a PTO under the CAISO tariff and will operate the project upon completion.

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the attachment A (technical data) to the CAISO contact listed in section 3. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to be considered in the CAISO Transmission Plan. This submission is for (check one)[1]:

   - ☒ Reliability Transmission Project (refer to section 1 of attachment A)
   - ☐ Merchant Transmission Facility (refer to section 1 of attachment A)
   - ☐ Economic Transmission Project (refer to section 1 of attachment A)
   - ☐ Location Constrained Resource Interconnection Facility (LCRIF) (refer to sections 1 & 2 of attachment A)
   - ☐ Project to preserve Long-term Congestion Revenue Rights (CRR) (refer to section 1 of attachment A)
   - ☐ Economic Planning Study Request (refer to section 3 of attachment A)
   - ☐ Others (refer to section 4 of attachment A)

2. For the submission of a Reliability, Merchant, Economic, LCRIF, and CRR project, the project sponsor is

   - ☒ Seeking ISO approval in this planning cycle
   - ☐ Submitting for information only (not requiring ISO approval in this planning cycle)

3. Please provide the following basic information about this submission:

   a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

      Project Name: **Guernsey 70kV Energy Storage Project**

      Submission Date: **November 30, 2009**

   b. Project locations or the proposed interconnection point(s) :

      PG&E's Guernsey 70kV Substation

   c. Project capacity (Net MW):

      Initially 7MW of energy storage will be installed at the Guernsey 70kV substation. Additional storage will be added every 5 years to maintain system reliability and account for load growth. The table below outlines the amount of storage that is required from years 1-30.

[1] Please contact the ISO staff at requestwindow@caiso.com for any questions regarding the definitions of these submission categories in this form to the ISO

Guernsey 70kV	
Year	Storage Device Size (MW)
5	7
10	8
15	9
20	11
25	12
30	14

Table 1: Required Storage device size

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project e.g. overall scope, objectives etc.

The Corcoran-Guernsey 70kV line is normally open. In an outage of Guernsey-Henrietta 70kV line, the Corcoran-Guernsey 70kV line can be closed to pick up the lost load; however the Corcoran source cannot support both Guernsey and Corcoran load.

In addition to PG&E's listed concerns about this region the CAISO Reliability assessment results (September 15, 2009) identify that the Corcoran 115kV/70kV bank will reach 105% of its normal rating by 2014. The WECC 2009 base case has the Corcoran 115kV/70kV at 100% of its normal rating.

PG&E is proposing a conversion of the Guernsey 70kV substation to 115kV operation, a new 115kV transmission line from Guernsey to GWF switching station, and a conversion of the Corcoran-Guernsey 70kV line to 115kV operation. This setup will leave Jacob's Corner on a radial feed from Henrietta. PG&E has a proposed in-service date of May 2016. PG&E is projecting the project to cost $10-$15M.

WGD is proposing a less costly alternative which includes installing a 7MW battery storage device at either the Corcoran or Guernsey 60kV substations in 2010, followed by six additional battery storage installations (one every 5 years) to account for load growth. If the battery is installed at Guernsey, then Guernsey would need to be normally fed from Corcoran in order to prevent the normal overload of the Corcoran 115/60kV bank. This project will resolve reliability concerns for 30 years.

Economic analysis indicates that the WGD solution has a levelized annual revenue requirement of $5.8M compared to $6.3M for PG&E. The overall project cost was calculated at $71.9M NPV compared to $77.7M NPV for PG&E with an additional $8.1M in Power Quality and Reliability savings. The PG&E to WGD cost ratio is 1.19% indicating a economic benefit as the WGD project is 19% cheaper than the PG&E proposed solution.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**12 / 30 / 2010**
Proposed Trial Operation date:	**12 / 30 / 2010**
Proposed Commercial Operation date:	**12 / 30 / 2010**
Proposed Term of Service:	**30 Years**

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
CAISO TRANSMISSION PLANNING PROCESS
REQUEST WINDOW SUBMISSION FORM

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member**
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

4. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Young
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

5. This Request is submitted by: **Western Grid Development, LLC**

Name of the Customer:	**Western Grid Development, LLC**
By (signature):	John Dizard
Name (type or print):	**John Dizard**
Title:	Managing Member
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**November 30, 2009**

General Data

Description of Project

Please see the attached report which includes a full reliability analysis and economic analysis on all WGD proposed projects.

The PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) included a single line diagram of the Guernsey 70kV area as shown below in figure 1.

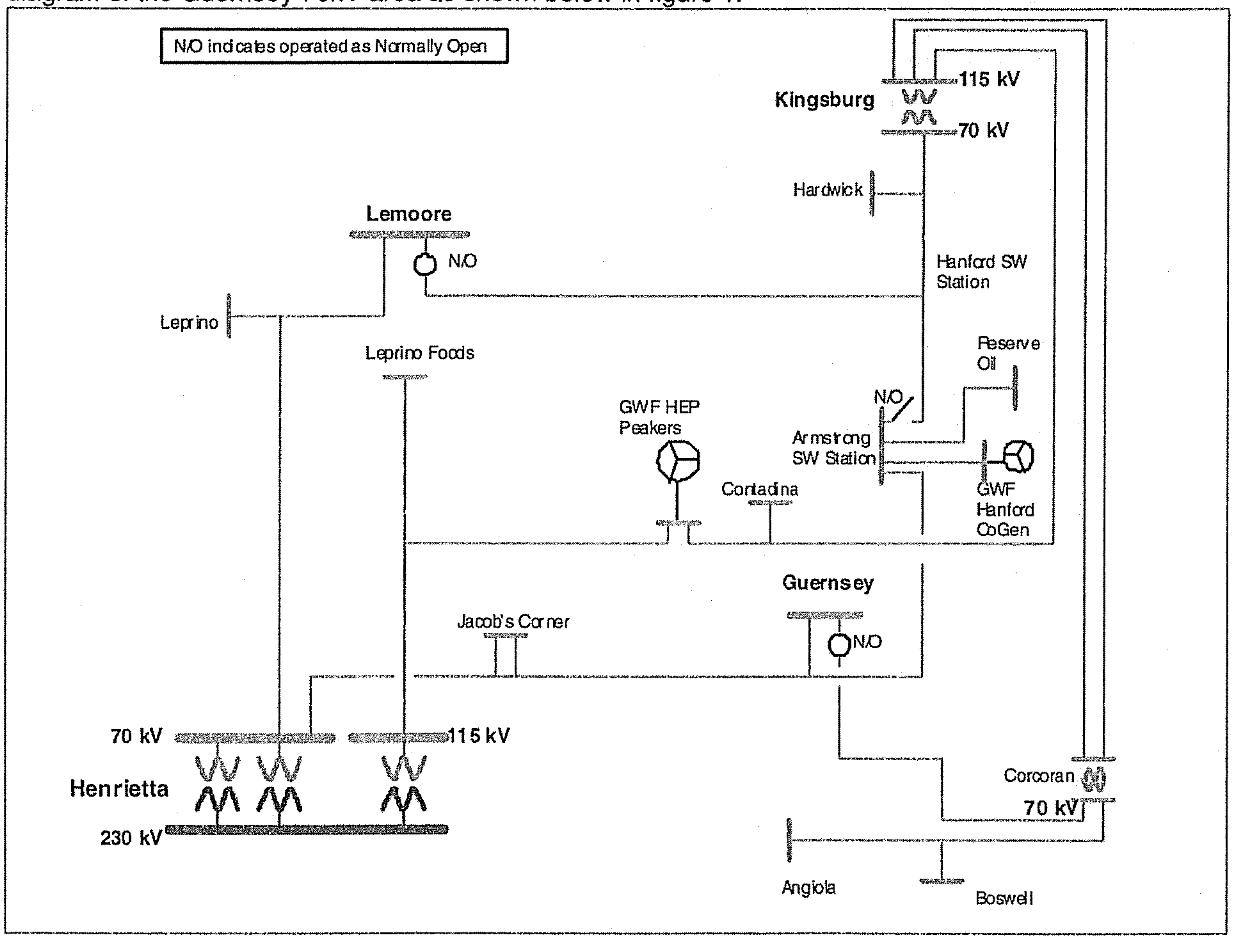


Figure 1: Guernsey 70kV Area

The Corcoran-Guernsey 70kV line is normally open. In an outage of Guernsey-Henrietta 70kV line, the Corcoran-Guernsey 70kV line can be closed to pick up the lost load; however the Corcoran source cannot support both Guernsey and Corcoran load.
In addition to PG&E's listed concerns about this region the CAISO Reliability assessment results (September 15, 2009) identify that the Corcoran 115kV/70kV bank will reach 105% of its normal rating by 2014. The WECC 2009 base case has the Corcoran 115kV/70kV at 100% of its normal rating.
PG&E is proposing a conversion of the Guernsey 70kV substation to 115kV operation, a new 115kV transmission line from Guernsey to GWF switching station, and a conversion of the Corcoran-Guernsey 70kV line to 115kV operation. This setup will leave Jacob's Corner on a radial feed from Henrietta. PG&E has a proposed in-service date of May 2016. PG&E is projecting the project to cost $10-$15M.

WGD is proposing a less costly alternative which includes installing a 7MW battery storage device at either the Corcoran or Guernsey 60kV substations in 2010, followed by six additional battery storage installations (one every 5 years) to account for load growth. If the battery is installed at Guernsey, then Guernsey would need to be normally fed from Corcoran in order to prevent the normal overload of the Corcoran 115/60kV bank. This project will resolve reliability concerns for 30 years.

Our analysis indicates that the WGD solution has a levelized annual revenue requirement of $5.8M compared to $6.3M for PG&E. The overall project cost was calculated at $71.9M NPV compared to $77.7M NPV for PG&E with an additional $8.1M in Power Quality and Reliability savings. The PG&E to WGD cost ratio is 1.19% indicating a economic benefit as the WGD project is 19% cheaper than the PG&E proposed solution.

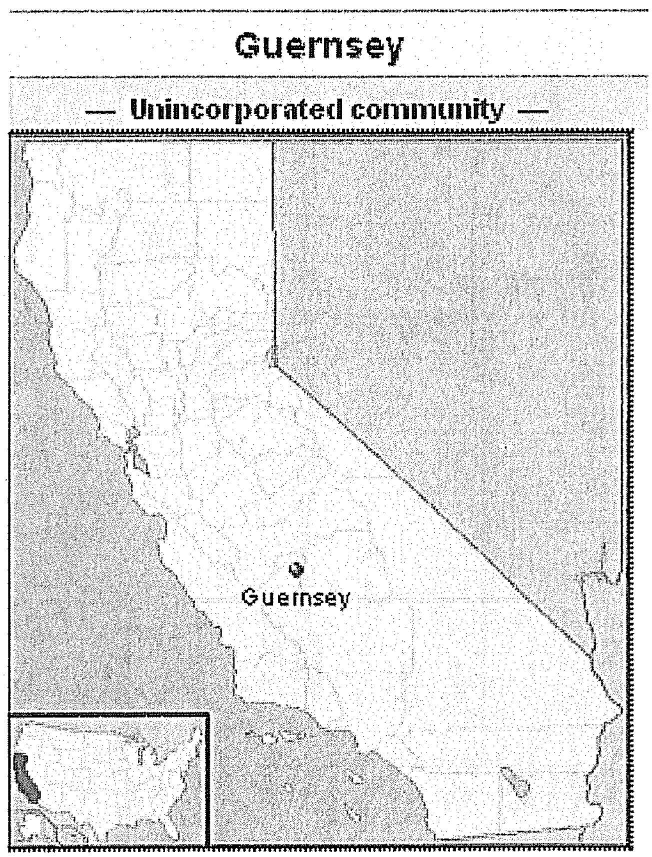


Figure 2: Guernsey Geographic Location

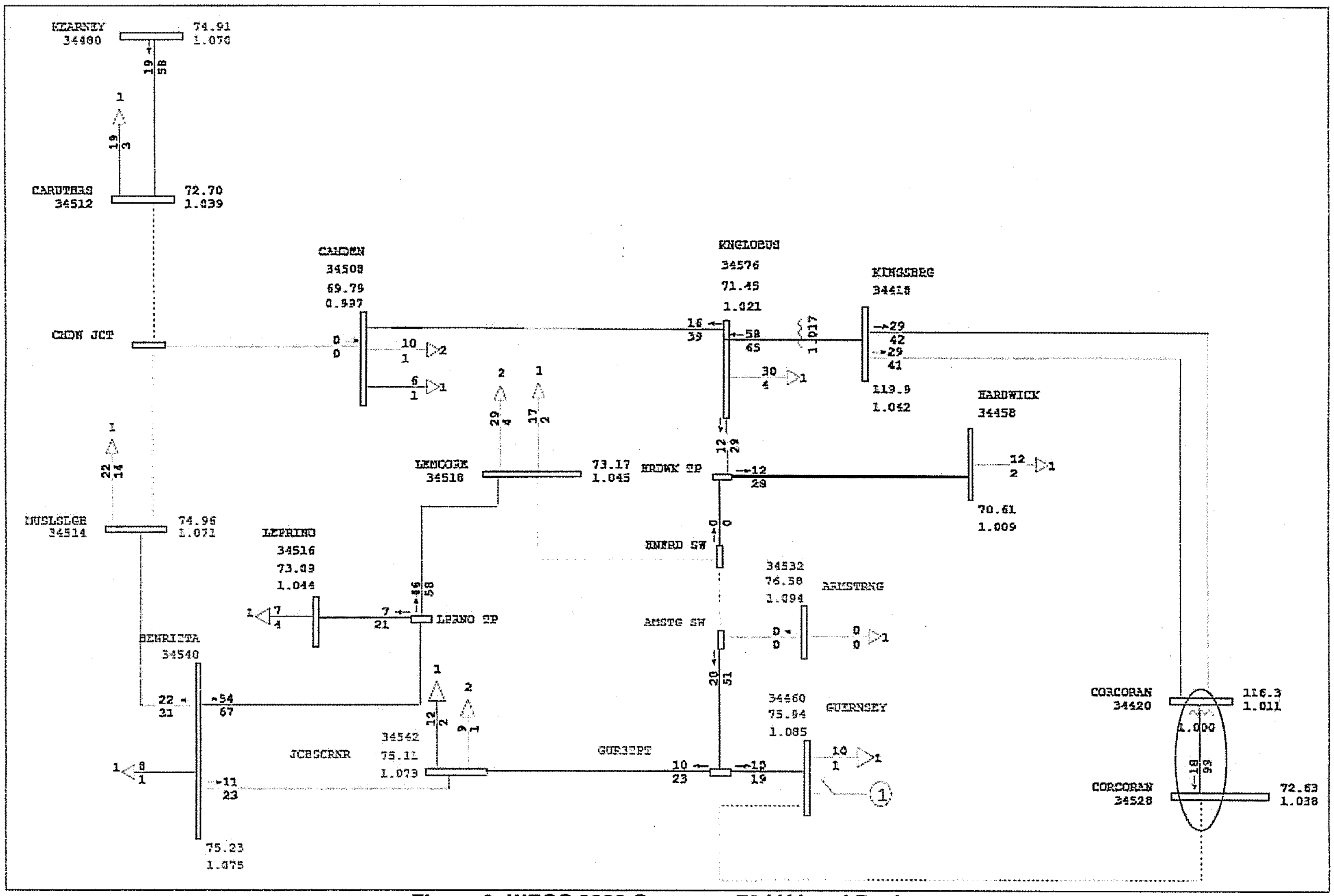


Figure 3: WECC 2009 Guernsey 70 kV Load Pocket

Required Storage Device Size

A load flow study was performed using the WECC 2009 heavy summer base case. The WECC 2009 heavy summer base case showed a 98.1% loading on the Corcoran 115/70kV bank and it is anticipated that the bank will reach its normal rating by 2010.

FROM	FNAME	FKV	TO	TNAME	TKV	CK	P	Q	MVA	AMPS	%RATE	RATE	UNIT
34420	CORCORAN	115	34528	CORCORAN	70	2	17.2	6.3	18.3	90.7	98.1	18.7	Mva

Table 2: 2009 Corcoran 115/ 70 kV Bank Flow

It was determined that approximately 7MW of battery storage device would be required to avoid the emergency overload of the Corcoran bank to allow for load transfer in the loss of the Guernsey-Henrietta 70kV line. 7MW of storage would be installed in 2010, and this would be sufficient to avoid the emergency overload of the Corcoran bank and allow for load transfer in the loss of the Guernsey-Henrietta 70kV line until 2015. In 2015 additional battery storage will be installed to meet load levels for the next five years. This cycle will continue until enough battery storage is installed to cover a 30 year project life.

Table 3 below shows the assumed 2015 load (5 year). Figure 4 shows the storage device placed at the Guernsey substation, along with the Corcoran 115/70kV bank loading.

Station Name	Assumed 2010 Load (MW)	5 year
Guernsey	10	10.7
Boswell	2	2
JGBSWLL	4.5	4.5
Angoila	11	11.7
Total Load	27.5	28.9
Required Battery		7.0

Table 3: Project Corcoran Pocket 2015 Load

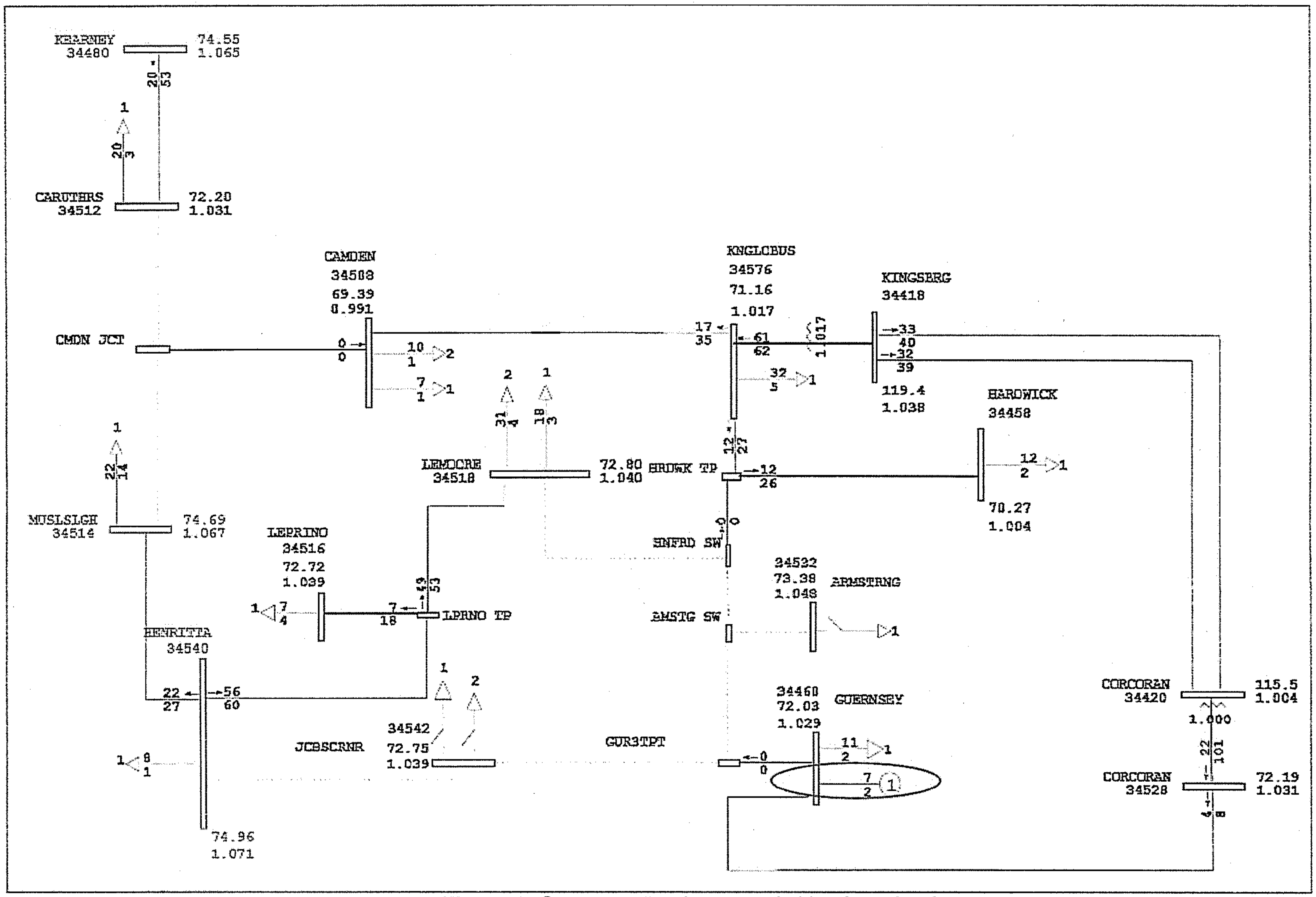


Figure 4: Guernsey Pocket 2015 (5 Year) Projection

The next step involved calculating the required battery size to replace the PG&E alternative for 30 years. The Guernsey 70kV load was increased at a rate of 3% per year. This rate was found in the CEC Staff Final Energy Demand Forecast Report. In the report the CEC states that 1.3% is the forecasted average annual growth in load from 2008-2020 as shown below in table 4.

Business-as-Usual Reference Case Source: CEC Staff Final Energy Demand Forecast Report, October 2007 Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	21,886	1.3%	81,532	95,598	1.3%
SCE	21,476	25,777	1.5%	87,966	106,018	1.6%
SDG&E	3,712	4,423	1.5%	18,687	22,651	1.6%
SMUD	3,174	3,741	1.4%	11,887	13,990	1.4%
LADWP	5,717	6,010	0.4%	28,004	29,592	0.5%
NorCalMunis	5,077	5,942	1.3%	35,720	39,440	0.8%
SoCalMunis	5,079	5,959	1.3%	35,148	38,276	0.7%
California	62,946	73,738	1.3%	298,945	345,566	1.2%

Table 4: CEC Energy Demand Forecast

It was found that a 14MW battery storage device at the Guernsey 70kV substation was required to keep the Corcoran 115kV/70kV bank below its emergency rating and transfer the Guernsey 70kV load thru 2015. The 2040 (30 year) Guernsey and Corcoran load values are in table 5 below, along with the required battery storage sizes to accommodate the load growth.

Station Name	Assumed 2010 Load (MW)	5 year	10 Year	15 year	20 year	25 year	2040 Expected Values (30 Year)
Guernsey	10	10.7	11.4	12.1	12.9	13.8	14.7
Boswell	2	2	2	2	2	2	2
JGBSWLL	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Angoila	11	11.7	12.5	13.4	14.2	15.2	16.2
Total Load	27.5	28.9	30.4	32.0	33.7	35.5	37.4
Required Battery		7.0	8	9	11	12	14.0

Table 5: Projected 30 Year Storage Device Size

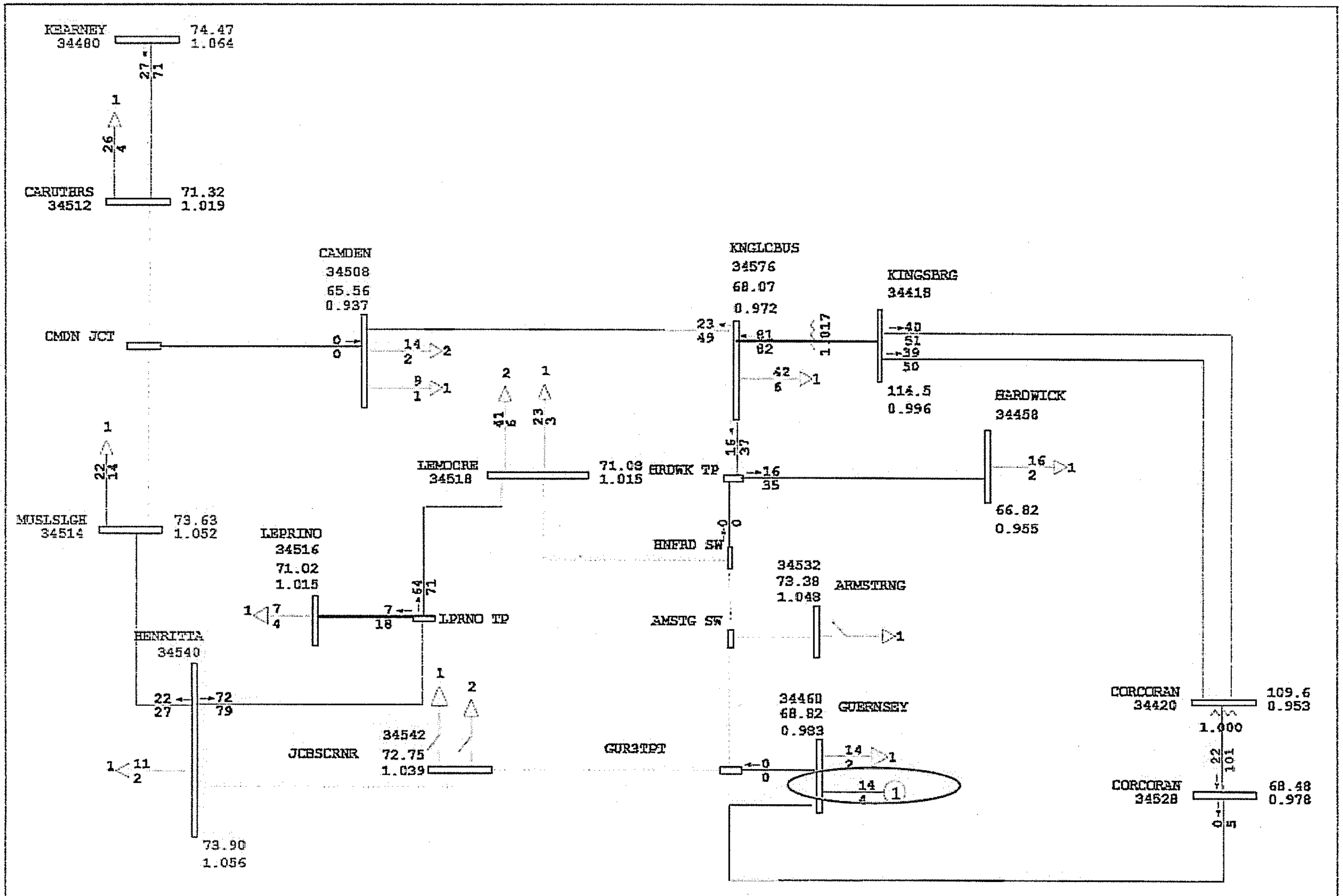


Figure 5: Guernsey Pocket 2040 (30 year) Projection

Economic Analysis

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

WGD proposes using a service life of 30 years.
Table 6 below shows the WGD ratemaking assumptions. For comparative purposes, these assumptions will match those listed by PG&E as shown in Table 7.

Install Date	Assumption	Value	Pre-Calculations	Note
	Battery Cost ($/MW)	$1,500,000.00		
Year 1	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$10,500,000.0**	-	7MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$350,000.00	
Year 5	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$1,704,082.7**	-	(8-7)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$56,802.76	
Year 10	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$1,884,718.3	-	(9-8)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$62,823.94	
Year 15	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$2,081,871.0**	-	(11-9)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$69,395.70	
Year 20	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$2,296,940.8**	-	(12-11)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$76,564.69	
Year 25	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	**$2,532,387.2**	-	(14-12)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$84,412.91	
	O&M = Operations and Maintanance	17.9%	-	
	A&G = Administrative and General	7.30%	-	
	Cost of Capital	9.27%	-	
	Taxes	22.4%	-	
	i = Interest Rate	7.00%	-	

Table 6: WGD Ratemaking Assumptions

Assumption	Value	re-Calculation
n = Asset Life (Years)	30	-
Salvage Value ($)	$0.0	-
Capital Cost ($)	$15,000,000.0	-
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$500,000.00
O&M = Operations and Maintanance	17.9%	-
A&G = Administrative and General	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 7: PG&E Ratemaking Assumptions

Using the assumptions listed above, our analysis indicates indicates that the WGD solution has a levelized annual revenue requirement of $5.8M compared to $6.3M for PG&E. The overall project cost was calculated at $71.9M NPV compared to $77.7M NPV for PG&E with an additional $8.1M in Power Quality and Reliability savings. The PG&E to WGD cost ratio is 1.19% indicating a economic benefit as the WGD project is 19% cheaper than the PG&E proposed solution.

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Power Quality & Reliability	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 10,500,000	$ 350,000	$ 973,350	$ 1,879,500	$ 766,500	$ 2,352,000	$ (506,721)	$ 6,321,350	$ 5,907,804	$ 5,797,451
1	$ 10,150,000	$ 350,000	$ 940,905	$ 1,816,850	$ 740,950	$ 2,273,600	$ (506,721)	$ 6,122,305	$ 5,347,458	
2	$ 9,800,000	$ 350,000	$ 908,460	$ 1,754,200	$ 715,400	$ 2,195,200	$ (506,721)	$ 5,923,260	$ 4,836,145	
3	$ 9,450,000	$ 350,000	$ 876,015	$ 1,691,550	$ 689,850	$ 2,116,800	$ (506,721)	$ 5,724,215	$ 4,366,976	
4	$ 9,100,000	$ 350,000	$ 843,570	$ 1,628,900	$ 664,300	$ 2,038,400	$ (506,721)	$ 5,525,170	$ 3,939,370	
5	$ 10,454,083	$ 406,803	$ 969,093	$ 1,871,281	$ 763,148	$ 2,341,715	$ (588,958)	$ 6,352,040	$ 4,232,632	
6	$ 10,047,280	$ 406,803	$ 931,383	$ 1,798,463	$ 733,451	$ 2,250,591	$ (588,958)	$ 6,120,691	$ 3,811,659	
7	$ 9,640,477	$ 406,803	$ 893,672	$ 1,725,645	$ 703,755	$ 2,159,467	$ (588,958)	$ 5,889,342	$ 3,427,651	
8	$ 9,233,674	$ 406,803	$ 855,962	$ 1,652,828	$ 674,058	$ 2,068,343	$ (588,958)	$ 5,657,993	$ 3,077,574	
9	$ 8,826,872	$ 406,803	$ 818,251	$ 1,580,010	$ 644,362	$ 1,977,219	$ (588,958)	$ 5,426,645	$ 2,758,631	
10	$ 10,304,787	$ 469,627	$ 955,254	$ 1,844,557	$ 752,249	$ 2,308,272	$ (679,913)	$ 6,329,959	$ 3,007,318	
11	$ 9,835,161	$ 469,627	$ 911,719	$ 1,760,494	$ 717,967	$ 2,203,076	$ (679,913)	$ 6,062,882	$ 2,691,992	
12	$ 9,365,534	$ 469,627	$ 868,185	$ 1,676,431	$ 683,684	$ 2,097,880	$ (679,913)	$ 5,795,806	$ 2,405,053	
13	$ 8,895,907	$ 469,627	$ 824,651	$ 1,592,367	$ 649,401	$ 1,992,683	$ (679,913)	$ 5,528,729	$ 2,144,136	
14	$ 8,426,280	$ 469,627	$ 781,116	$ 1,508,304	$ 615,118	$ 1,887,487	$ (679,913)	$ 5,261,652	$ 1,907,065	
15	$ 10,038,525	$ 539,022	$ 930,571	$ 1,796,896	$ 732,812	$ 2,248,630	$ (780,383)	$ 6,247,931	$ 2,116,391	
16	$ 9,499,502	$ 539,022	$ 880,604	$ 1,700,411	$ 693,464	$ 2,127,889	$ (780,383)	$ 5,941,389	$ 1,880,892	
17	$ 8,960,480	$ 539,022	$ 830,636	$ 1,603,926	$ 654,115	$ 2,007,148	$ (780,383)	$ 5,634,847	$ 1,667,148	
18	$ 8,421,458	$ 539,022	$ 780,669	$ 1,507,441	$ 614,766	$ 1,886,406	$ (780,383)	$ 5,328,305	$ 1,473,321	
19	$ 7,882,435	$ 539,022	$ 730,702	$ 1,410,956	$ 575,418	$ 1,765,665	$ (780,383)	$ 5,021,763	$ 1,297,719	
20	$ 9,640,354	$ 615,587	$ 893,661	$ 1,725,623	$ 703,746	$ 2,159,439	$ (891,231)	$ 6,098,056	$ 1,472,760	
21	$ 9,024,766	$ 615,587	$ 836,596	$ 1,615,433	$ 658,808	$ 2,021,548	$ (891,231)	$ 5,747,972	$ 1,297,393	
22	$ 8,409,179	$ 615,587	$ 779,531	$ 1,505,243	$ 613,870	$ 1,883,656	$ (891,231)	$ 5,397,887	$ 1,138,668	
23	$ 7,793,592	$ 615,587	$ 722,466	$ 1,395,053	$ 568,932	$ 1,745,765	$ (891,231)	$ 5,047,803	$ 995,157	
24	$ 7,178,005	$ 615,587	$ 665,401	$ 1,284,863	$ 523,994	$ 1,607,873	$ (891,231)	$ 4,697,719	$ 865,551	
25	$ 9,094,805	$ 700,000	$ 843,088	$ 1,627,970	$ 663,921	$ 2,037,236	$ (1,013,442)	$ 5,872,216	$ 1,011,169	
26	$ 8,394,805	$ 700,000	$ 778,198	$ 1,502,670	$ 612,821	$ 1,880,436	$ (1,013,442)	$ 5,474,126	$ 880,953	
27	$ 7,694,805	$ 700,000	$ 713,308	$ 1,377,370	$ 561,721	$ 1,723,636	$ (1,013,442)	$ 5,076,036	$ 763,447	
28	$ 6,994,805	$ 700,000	$ 648,418	$ 1,252,070	$ 510,621	$ 1,566,836	$ (1,013,442)	$ 4,677,946	$ 657,545	
29	$ 6,294,805	$ 700,000	$ 583,528	$ 1,126,770	$ 459,521	$ 1,410,036	$ (1,013,442)	$ 4,279,856	$ 562,232	
TOTAL	$ 269,352,378	$ 15,405,195	$ 24,968,965	$ 48,214,076	$ 19,662,724	$ 60,334,933	$ (22,303,240)	$ 168,585,892	$ 71,940,810	

Table 8: WGD Alternative Project Cost

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement	Levilized income
0	$ 15,000,000	$ 500,000	$ 1,390,500	$ 2,685,000	$ 1,095,000	$ 3,360,000	$ 9,030,500	$ 8,439,720	$ 6,258,462	$ 938,648
1	$ 14,500,000	$ 500,000	$ 1,344,150	$ 2,595,500	$ 1,058,500	$ 3,248,000	$ 8,746,150	$ 7,639,226		
2	$ 14,000,000	$ 500,000	$ 1,297,800	$ 2,506,000	$ 1,022,000	$ 3,136,000	$ 8,461,800	$ 6,907,349		
3	$ 13,500,000	$ 500,000	$ 1,251,450	$ 2,416,500	$ 985,500	$ 3,024,000	$ 8,177,450	$ 6,238,537		
4	$ 13,000,000	$ 500,000	$ 1,205,100	$ 2,327,000	$ 949,000	$ 2,912,000	$ 7,893,100	$ 5,627,671		
5	$ 12,500,000	$ 500,000	$ 1,158,750	$ 2,237,500	$ 912,500	$ 2,800,000	$ 7,608,750	$ 5,070,031		
6	$ 12,000,000	$ 500,000	$ 1,112,400	$ 2,148,000	$ 876,000	$ 2,688,000	$ 7,324,400	$ 4,561,268		
7	$ 11,500,000	$ 500,000	$ 1,066,050	$ 2,058,500	$ 839,500	$ 2,576,000	$ 7,040,050	$ 4,097,373		
8	$ 11,000,000	$ 500,000	$ 1,019,700	$ 1,969,000	$ 803,000	$ 2,464,000	$ 6,755,700	$ 3,674,653		
9	$ 10,500,000	$ 500,000	$ 973,350	$ 1,879,500	$ 766,500	$ 2,352,000	$ 6,471,350	$ 3,289,706		
10	$ 10,000,000	$ 500,000	$ 927,000	$ 1,790,000	$ 730,000	$ 2,240,000	$ 6,187,000	$ 2,939,399		
11	$ 9,500,000	$ 500,000	$ 880,650	$ 1,700,500	$ 693,500	$ 2,128,000	$ 5,902,650	$ 2,620,847		
12	$ 9,000,000	$ 500,000	$ 834,300	$ 1,611,000	$ 657,000	$ 2,016,000	$ 5,618,300	$ 2,331,395		
13	$ 8,500,000	$ 500,000	$ 787,950	$ 1,521,500	$ 620,500	$ 1,904,000	$ 5,333,950	$ 2,068,598		
14	$ 8,000,000	$ 500,000	$ 741,600	$ 1,432,000	$ 584,000	$ 1,792,000	$ 5,049,600	$ 1,830,207		
15	$ 7,500,000	$ 500,000	$ 695,250	$ 1,342,500	$ 547,500	$ 1,680,000	$ 4,765,250	$ 1,614,155		
16	$ 7,000,000	$ 500,000	$ 648,900	$ 1,253,000	$ 511,000	$ 1,568,000	$ 4,480,900	$ 1,418,538		
17	$ 6,500,000	$ 500,000	$ 602,550	$ 1,163,500	$ 474,500	$ 1,456,000	$ 4,196,550	$ 1,241,608		
18	$ 6,000,000	$ 500,000	$ 556,200	$ 1,074,000	$ 438,000	$ 1,344,000	$ 3,912,200	$ 1,081,756		
19	$ 5,500,000	$ 500,000	$ 509,850	$ 984,500	$ 401,500	$ 1,232,000	$ 3,627,850	$ 937,505		
20	$ 5,000,000	$ 500,000	$ 463,500	$ 895,000	$ 365,000	$ 1,120,000	$ 3,343,500	$ 807,499		
21	$ 4,500,000	$ 500,000	$ 417,150	$ 805,500	$ 328,500	$ 1,008,000	$ 3,059,150	$ 690,490		
22	$ 4,000,000	$ 500,000	$ 370,800	$ 716,000	$ 292,000	$ 896,000	$ 2,774,800	$ 585,335		
23	$ 3,500,000	$ 500,000	$ 324,450	$ 626,500	$ 255,500	$ 784,000	$ 2,490,450	$ 490,984		
24	$ 3,000,000	$ 500,000	$ 278,100	$ 537,000	$ 219,000	$ 672,000	$ 2,206,100	$ 406,472		
25	$ 2,500,000	$ 500,000	$ 231,750	$ 447,500	$ 182,500	$ 560,000	$ 1,921,750	$ 330,917		
26	$ 2,000,000	$ 500,000	$ 185,400	$ 358,000	$ 146,000	$ 448,000	$ 1,637,400	$ 263,507		
27	$ 1,500,000	$ 500,000	$ 139,050	$ 268,500	$ 109,500	$ 336,000	$ 1,353,050	$ 203,502		
28	$ 1,000,000	$ 500,000	$ 92,700	$ 179,000	$ 73,000	$ 224,000	$ 1,068,700	$ 150,219		
29	$ 500,000	$ 500,000	$ 46,350	$ 89,500	$ 36,500	$ 112,000	$ 784,350	$ 103,038		
TOTAL	$ 232,500,000	$ 15,000,000	$21,552,750	$ 41,617,500	$ 16,972,500	$ 52,080,000	$ 147,222,750	$ 77,661,508		

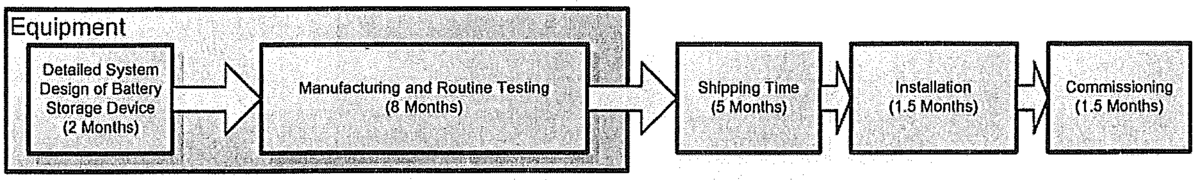
Table 9: PG&E Alternative Project Cost

Power Quality & Reliability Services	PV	
$ (506,721)	0.934579439	$ (473,570.93)
$ (506,721)	0.873438728	$ (442,589.65)
$ (506,721)	0.816297877	$ (413,635.19)
$ (506,721)	0.762895212	$ (386,574.94)
$ (506,721)	0.712986179	$ (361,284.99)
$ (588,958)	0.666342224	$ (392,447.88)
$ (588,958)	0.622749742	$ (366,773.72)
$ (588,958)	0.582009105	$ (342,779.18)
$ (588,958)	0.543933743	$ (320,354.37)
$ (588,958)	0.508349292	$ (299,396.61)
$ (679,913)	0.475092796	$ (323,021.92)
$ (679,913)	0.444011959	$ (301,889.64)
$ (679,913)	0.414964448	$ (282,139.85)
$ (679,913)	0.387817241	$ (263,682.11)
$ (679,913)	0.36244602	$ (246,431.87)
$ (780,383)	0.338734598	$ (264,342.59)
$ (780,383)	0.31657439	$ (247,049.15)
$ (780,383)	0.295863916	$ (230,887.05)
$ (780,383)	0.276508333	$ (215,782.29)
$ (780,383)	0.258419003	$ (201,665.69)
$ (891,231)	0.241513087	$ (215,243.94)
$ (891,231)	0.225713165	$ (201,162.56)
$ (891,231)	0.210946883	$ (188,002.40)
$ (891,231)	0.19714662	$ (175,703.17)
$ (891,231)	0.184249178	$ (164,208.57)
$ (1,013,442)	0.172195493	$ (174,510.11)
$ (1,013,442)	0.160930367	$ (163,093.56)
$ (1,013,442)	0.150402212	$ (152,423.89)
$ (1,013,442)	0.140562815	$ (142,452.23)
$ (1,013,442)	0.131367117	$ (133,132.93)
	TOTAL	$ (8,086,233)

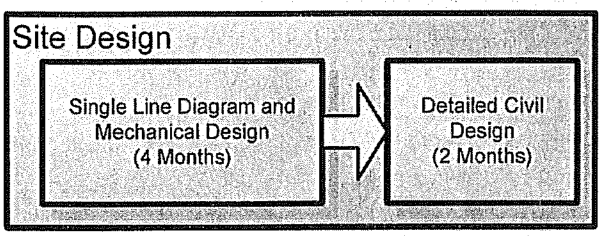
Table10 :Power Quality & Reliability Service Benefit

Construction schedule and expected online date:

The chart below outlines the estimated schedule of 18 months



During the 10 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Technical Data

The following pieces of technical information are attached to this application:

- Network model for power flow study in GE-PSLF format
    - guernsey.epc
- GE PSLF Batt model and model parameters
    - PSLF_batt_Model.pdf
    - BATT_epcl_parameters.xls
- Sample one line diagram
    - NAS Battery System SLD.pdf

Miscellaneous Data

Proposed entity to construct, own, and finance the project

Western Grid Development, LLC (WGD) will own the storage device project and will act as project manager during construction. WGD will also be responsible for financing the project.

Planned operator of the project

WGD will file to become a PTO under the CAISO tariff and will operate the project upon completion.

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the attachment A (technical data) to the CAISO contact listed in section 3. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to be considered in the CAISO Transmission Plan. This submission is for (check one)[1]:

   ☒ Reliability Transmission Project (refer to section 1 of attachment A)

   ☐ Merchant Transmission Facility (refer to section 1 of attachment A)

   ☐ Economic Transmission Project (refer to section 1 of attachment A)

   ☐ Location Constrained Resource Interconnection Facility (LCRIF) (refer to sections 1 & 2 of attachment A)

   ☐ Project to preserve Long-term Congestion Revenue Rights (CRR) (refer to section 1 of attachment A)

   ☐ Economic Planning Study Request (refer to section 3 of attachment A)

   ☐ Others (refer to section 4 of attachment A)

2. For the submission of a Reliability, Merchant, Economic, LCRIF, and CRR project, the project sponsor is

   ☒ Seeking ISO approval in this planning cycle

   ☐ Submitting for information only (not requiring ISO approval in this planning cycle)

3. Please provide the following basic information about this submission:

   a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

      Project Name: **Auburn 60kV Energy Storage Project**

      Submission Date: **November 30, 2009**

   b. Project locations or the proposed interconnection point(s) :

      PG&E's Auburn 60kV Substation

   c. Project capacity (Net MW):

      29MW

   d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project e.g. overall scope, objectives etc.

      PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) states that the Placer 115/60kV transformer #1 will reach its capacity as electric demand continues to grow. Currently, the Placer 115/60kV transformer bank

[1] Please contact the ISO staff at requestwindow@caiso.com for any questions regarding the definitions of these submission categories in this form to the ISO

radially serves customers at the PENRYN, SIERRAPI, AUBURN, MRN_QUAR, HALSEY 60kV substations.

PG&E is proposing to convert the Atlantic-Placer 60kV system to 115kV service. PG&E is proposing a May 2015 in-service date and the project is estimated by PG&E to cost between $50-$60M. It is assumed that the bank will overload in 2015, as that is the PG&E proposed in-service date.

WGD is proposing a less costly alternative which includes installing a 29MW battery storage device in 2015. This proposed alternative would solve the Placer 60kV load pocket's reliability concerns for 30 years.

Analysis indicates that the WGD solution has a levelized annual revenue requirement of $18.8M compared to $22.9M for PG&E. The overall project cost was calculated at $233.4M NPV compared to $284.8M NPV for PG&E with an additional $26M in Reliability and Power Quality benefits. The PG&E to WGD cost ratio is 1.33% indicating a large economic benefit as the WGD project is 33% cheaper than the PG&E proposed solution.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**03 / 30 / 2015**
Proposed Trial Operation date:	**03 / 30 / 2015**
Proposed Commercial Operation date:	**03 / 30 / 2015**
Proposed Term of Service:	**30 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member**
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

g. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

4. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Young

Regional Transmission

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
CAISO TRANSMISSION PLANNING PROCESS
REQUEST WINDOW SUBMISSION FORM

California ISO

151 Blue Ravine Road, Folsom, CA 95630

5. This Request is submitted by: **Western Grid Development, LLC**

Name of the Customer:	**Western Grid Development, LLC**
By (signature):	(John Dizard)
Name (type or print):	**John Dizard**
Title:	Managing Member
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**November 30, 2009**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

This section applies to all transmission project submissions. It does not apply to Economic Planning Study Requests.

Any transmission project, including those seeking cost recovery through Long-term Congestion Revenue Rights, whether submitted by a PTO, non-PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[2]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route

Technical Data

- Network model for power flow study in GE-PSLF format. In some cases, Dynamic models for stability study in GE-PSLF format may also be required

Planning Level Cost Data[3]

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[2] This appendix lists the minimum amount of data required by the ISO for the first screening purposes. Additional data may be requested by the ISO later during the course of project evaluation

[3] Not required for Merchant Transmission Facilities

2. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets applicable reliability requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

3. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives, must be provided to CAISO by the closing date of Request Window.

4. Submission under "Other" category

This category of submission includes other type of proposals that may be considered as alternatives in the transmission planning process such as generation, demand response programs, new technologies etc. However, the ISO encourages project sponsors to contact CAISO staff prior to submitting these proposals through the Request Window.

General Data

Description of Project

Please see the attached report which includes a full reliability analysis and economic analysis on all WGD proposed projects.

The PG&E's 2009 Electric Transmission Grid Expansion Plan (March 5, 2009) states that the Placer 115/60kV transformer #1 will reach its capacity as electric demand continues to grow. Currently, the Placer 115/60kV transformer bank radially serves customers at the PENRYN, SIERRAPI, AUBURN, MRN_QUAR, HALSEY 60kV substations.

PG&E is proposing to convert the Atlantic-Placer 60kV system to 115kV service. PG&E is proposing a May 2015 in-service date and the project is estimated by PG&E to cost between $50-$60M. It is assumed that the bank will overload in 2015, as that is the PG&E proposed in-service date.

WGD is proposing a less costly alternative which includes installing a 29MW battery storage device in 2015. This proposed alternative would solve the Placer 60kV load pocket's reliability concerns for 30 years.

Using the assumptions listed above, our analysis indicates that the WGD solution has a levelized annual revenue requirement of $18.8M compared to $22.9M for PG&E. The overall project cost was calculated at $233.4M NPV compared to $284.8M NPV for PG&E with an additional $26M in Reliability and power quality benefits. The PG&E to WGD cost ratio is 1.33% indicating a large economic benefit as the WGD project is 33% cheaper than the PG&E proposed solution.

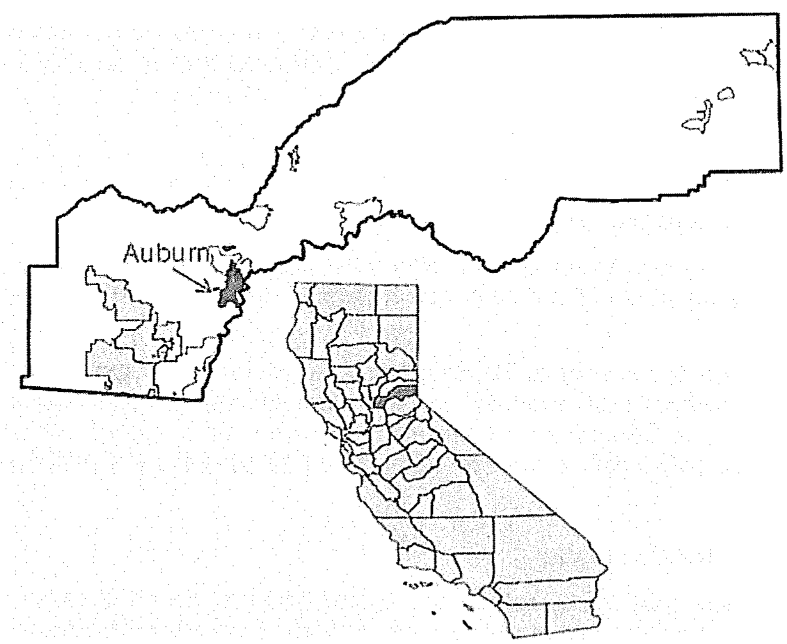


Figure 1: Auburn Geographical Location

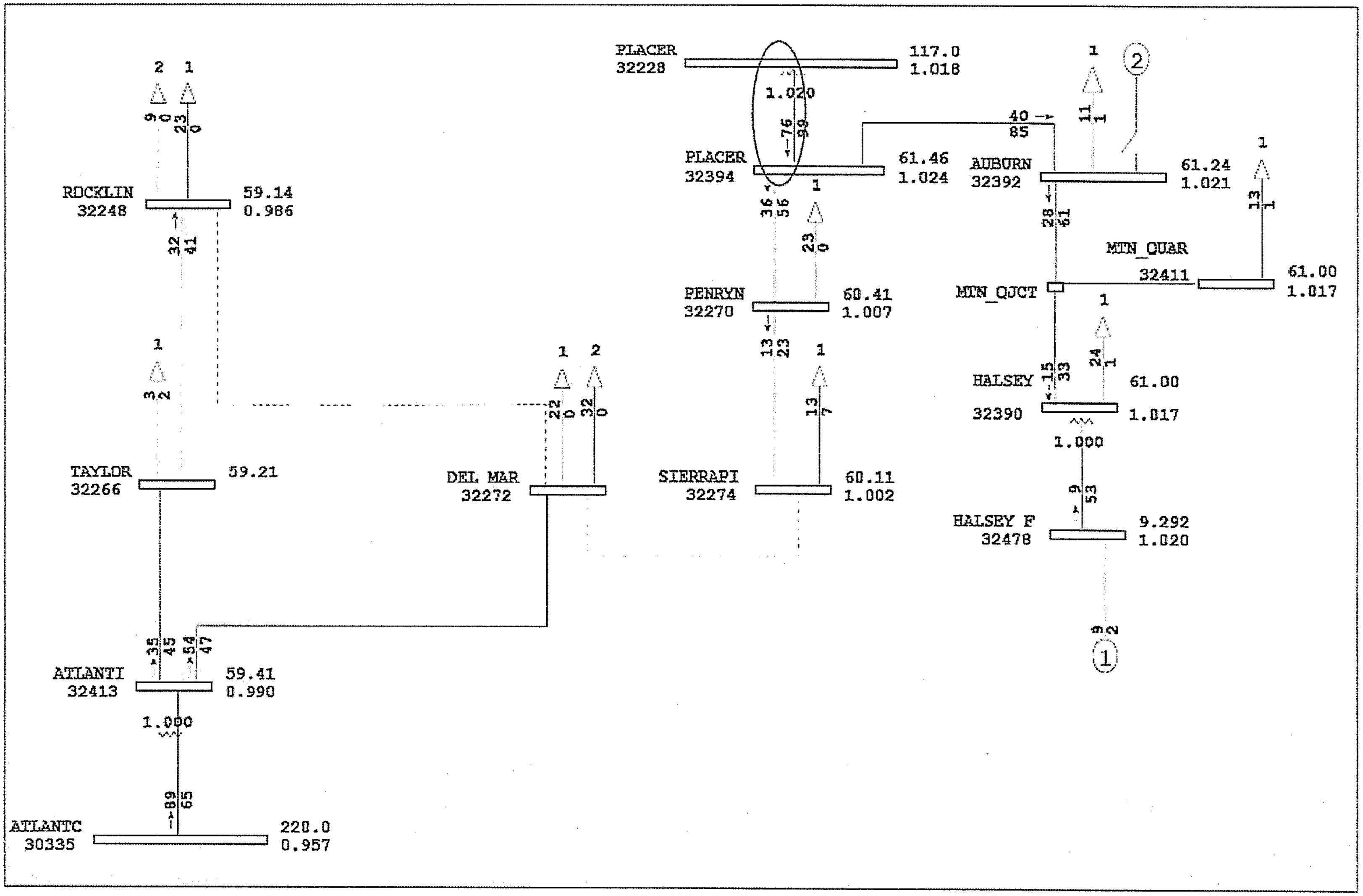


Figure 2: Placer 60kV Load Pocket

Required Storage Device Size

A load flow study was performed using the WECC 2015 heavy summer base case. PG&E identified a project in-service date of 2015 therefore an assumption was made that the bank will reach its normal rating by 2015. The load in the Placer 60kV pocket was increased until the Placer 115/60kV transformer reached 101% of its normal rating of 77MVA as shown in table 1 below and addition the 2015 Placer 60kV load is shown in table 2 below.

FROM	FNAME	FKV	TO	TNAME	TKV	CK	P	Q	MVA	AMPS	%RATE	RATE	UNIT
32228	PLACER	115	32394	PLACER	60	1	75.6	18.5	77.8	394.9	101	77	Mva

Table 1: 2015 Placer 115/60kV Bank Flow

Auburn 60kV	2015 Scaled Load (WECC 15hs1sa.sav)
PENRYN	22.8
AUBURN	11.3
MTN QAUR	13
HASLEY	23.6
SIERRAPI	13
Total Load	83.7

Table 2: Projected Placer 60 kV 2015 Load

The next step involved calculating the required battery size to replace the PG&E alternative for 30 years. The Placer 60kV load was increased at a rate of 3% per year. This rate was found in the CEC Staff Final Energy Demand Forecast Report. In the report the CEC states that 1.3% is the forecasted average annual growth in load from 2008-2020 as shown below in table 3.

Business-as-Usual Reference Case						
Source: CEC Staff Final Energy Demand Forecast Report, October 2007						
Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	21,886	1.3%	81,532	95,598	1.3%
SCE	21,476	25,777	1.5%	87,966	106,018	1.6%
SDG&E	3,712	4,423	1.5%	18,687	22,651	1.6%
SMUD	3,174	3,741	1.4%	11,887	13,990	1.4%
LADWP	5,717	6,010	0.4%	28,004	29,592	0.5%
NorCalMunis	5,077	5,942	1.3%	35,720	39,440	0.8%
SoCalMunis	5,079	5,959	1.3%	35,148	38,276	0.7%
California	62,946	73,738	1.3%	298,945	345,566	1.2%

Table 3: CEC Energy Demand Forecast

It was found that a 29MW battery storage device at the Auburn 60kV substation was required to keep the Placer 115/60kV bank below its normal rating thru 2045. Table 4 below shows the 2045 bank rating after the addition of a 29MW transformer at the Auburn 60kV substation. In addition the 2045 Placer 60kV load values are in tables 4 and 5.

FROM	FNAME	FKV	TO	TNAME	TKV	CK	P	Q	MVA	AMPS	%RATE	RATE	UNIT
32228	PLACER	115	32394	PLACER	60	1	76.2	14.8	77.6	382.9	100	77	Mva

Table 4: 2045 Post Placer 11560 kV Bank Flow

Auburn 60kV	2015 Scaled Load (WECC 15hs1sa.sav)	2045 Expected Values (30 Year)
PENRYN	22.8	33.6
AUBURN	11.3	16.6
MTN QAUR	13	19.2
HASLEY	23.6	34.8
SIERRAPI	13	13
Total Load	83.7	117.2

*NOTE: SIERRAPI is non conforming load; therefore it did not adjust over time.

Table: 5 Projected Placer 60kV and 2045 Load

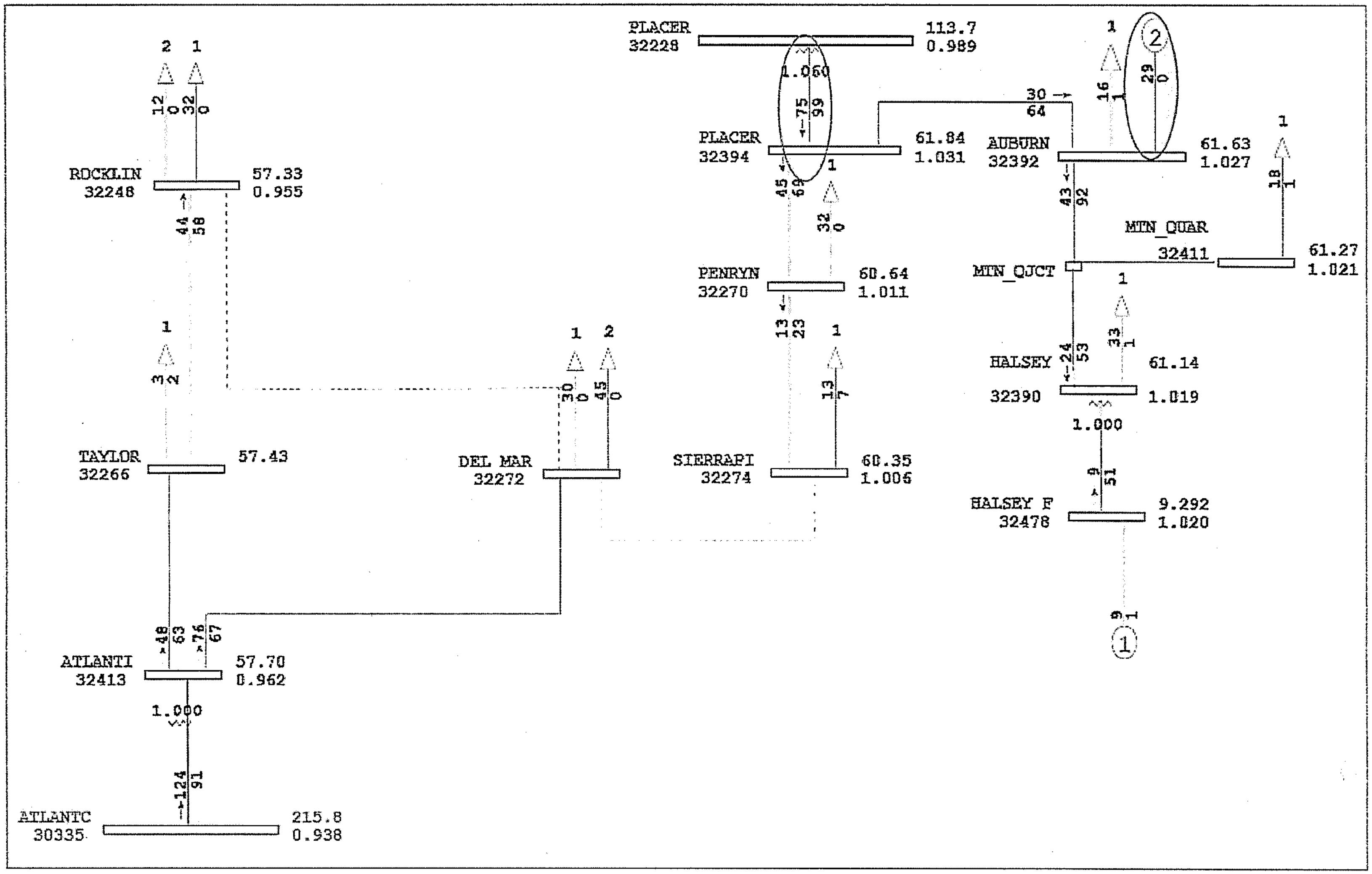


Figure 3: 2045 Post WGD Project Placer 115/60kV Bank Load

Economic Analysis

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

WGD proposes using a service life of 30 years and a net salvage rate of 10.00%.Table 6 below shows the WGD ratemaking assumptions. For comparative purposes, these assumptions will match those listed by PG&E as shown in Table 7.

Assumption	Value	Pre-Calculations
n = Asset Life (Years)	30	-
Salvage Value ($)	$4,350,000.0	10%
Capital Cost ($)	$43,500,000.0	29MW*$1.5M
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$1,305,000.00
O&M = Operations and Maintanance	17.9%	-
A&G = Administrative and General	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 6: WGD Ratemaking Assumptions

Assumption	Value	Pre-Calculations	Note
n = Asset Life (Years)	30	-	
Salvage Value ($)	$0.0	-	
Capital Cost ($)	$55,000,000.0	-	PG&E lists cost $50-$60M
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$1,833,333.33	
O&M = Operations and Maintanance	17.9%	-	
A&G = Administrative and General	7.30%	-	
Cost of Capital	9.27%	-	
Taxes	22.4%	-	
i = Interest Rate	7.00%	-	

Table 7: PG&E Ratemaking Assumptions

Using the assumptions listed above, our analysis indicates that the WGD solution has a levelized annual revenue requirement of $18.8M compared to $22.9M for PG&E. The overall project cost was calculated at $233.4M NPV compared to $284.8M NPV for PG&E with an additional $26M in Reliability and power quality benefits. The PG&E to WGD cost ratio is 1.33% indicating a large economic benefit as the WGD project is 33% cheaper than the PG&E proposed solution.

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement	Levilized income
0	$ 43,500,000	$ 1,305,000	$ 4,032,450	$ 7,786,500	$ 3,175,500	$ 9,744,000	$ 26,043,450	$ 24,339,673	$ 18,808,430	$ 2,853,118
1	$ 42,195,000	$ 1,305,000	$ 3,911,477	$ 7,552,905	$ 3,080,235	$ 9,451,680	$ 25,301,297	$ 22,099,132		
2	$ 40,890,000	$ 1,305,000	$ 3,790,503	$ 7,319,310	$ 2,984,970	$ 9,159,360	$ 24,559,143	$ 20,047,576		
3	$ 39,585,000	$ 1,305,000	$ 3,669,530	$ 7,085,715	$ 2,889,705	$ 8,867,040	$ 23,816,990	$ 18,169,867		
4	$ 38,280,000	$ 1,305,000	$ 3,548,556	$ 6,852,120	$ 2,794,440	$ 8,574,720	$ 23,074,836	$ 16,452,039		
5	$ 36,975,000	$ 1,305,000	$ 3,427,583	$ 6,618,525	$ 2,699,175	$ 8,282,400	$ 22,332,683	$ 14,881,209		
6	$ 35,670,000	$ 1,305,000	$ 3,306,609	$ 6,384,930	$ 2,603,910	$ 7,990,080	$ 21,590,529	$ 13,445,496		
7	$ 34,365,000	$ 1,305,000	$ 3,185,636	$ 6,151,335	$ 2,508,645	$ 7,697,760	$ 20,848,376	$ 12,133,944		
8	$ 33,060,000	$ 1,305,000	$ 3,064,662	$ 5,917,740	$ 2,413,380	$ 7,405,440	$ 20,106,222	$ 10,936,453		
9	$ 31,755,000	$ 1,305,000	$ 2,943,689	$ 5,684,145	$ 2,318,115	$ 7,113,120	$ 19,364,069	$ 9,843,711		
10	$ 30,450,000	$ 1,305,000	$ 2,822,715	$ 5,450,550	$ 2,222,850	$ 6,820,800	$ 18,621,915	$ 8,847,138		
11	$ 29,145,000	$ 1,305,000	$ 2,701,742	$ 5,216,955	$ 2,127,585	$ 6,528,480	$ 17,879,762	$ 7,938,828		
12	$ 27,840,000	$ 1,305,000	$ 2,580,768	$ 4,983,360	$ 2,032,320	$ 6,236,160	$ 17,137,608	$ 7,111,498		
13	$ 26,535,000	$ 1,305,000	$ 2,459,795	$ 4,749,765	$ 1,937,055	$ 5,943,840	$ 16,395,455	$ 6,358,440		
14	$ 25,230,000	$ 1,305,000	$ 2,338,821	$ 4,516,170	$ 1,841,790	$ 5,651,520	$ 15,653,301	$ 5,673,477		
15	$ 23,925,000	$ 1,305,000	$ 2,217,848	$ 4,282,575	$ 1,746,525	$ 5,359,200	$ 14,911,148	$ 5,050,922		
16	$ 22,620,000	$ 1,305,000	$ 2,096,874	$ 4,048,980	$ 1,651,260	$ 5,066,880	$ 14,168,994	$ 4,485,541		
17	$ 21,315,000	$ 1,305,000	$ 1,975,901	$ 3,815,385	$ 1,555,995	$ 4,774,560	$ 13,426,841	$ 3,972,518		
18	$ 20,010,000	$ 1,305,000	$ 1,854,927	$ 3,581,790	$ 1,460,730	$ 4,482,240	$ 12,684,687	$ 3,507,422		
19	$ 18,705,000	$ 1,305,000	$ 1,733,954	$ 3,348,195	$ 1,365,465	$ 4,189,920	$ 11,942,534	$ 3,086,178		
20	$ 17,400,000	$ 1,305,000	$ 1,612,980	$ 3,114,600	$ 1,270,200	$ 3,897,600	$ 11,200,380	$ 2,705,036		
21	$ 16,095,000	$ 1,305,000	$ 1,492,007	$ 2,881,005	$ 1,174,935	$ 3,605,280	$ 10,458,227	$ 2,360,559		
22	$ 14,790,000	$ 1,305,000	$ 1,371,033	$ 2,647,410	$ 1,079,670	$ 3,312,960	$ 9,716,073	$ 2,049,575		
23	$ 13,485,000	$ 1,305,000	$ 1,250,060	$ 2,413,815	$ 984,405	$ 3,020,640	$ 8,973,920	$ 1,769,178		
24	$ 12,180,000	$ 1,305,000	$ 1,129,086	$ 2,180,220	$ 889,140	$ 2,728,320	$ 8,231,766	$ 1,516,696		
25	$ 10,875,000	$ 1,305,000	$ 1,008,113	$ 1,946,625	$ 793,875	$ 2,436,000	$ 7,489,613	$ 1,289,678		
26	$ 9,570,000	$ 1,305,000	$ 887,139	$ 1,713,030	$ 698,610	$ 2,143,680	$ 6,747,459	$ 1,085,871		
27	$ 8,265,000	$ 1,305,000	$ 766,166	$ 1,479,435	$ 603,345	$ 1,851,360	$ 6,005,306	$ 903,211		
28	$ 6,960,000	$ 1,305,000	$ 645,192	$ 1,245,840	$ 508,080	$ 1,559,040	$ 5,263,152	$ 739,803		
29	$ 5,655,000	$ 1,305,000	$ 524,219	$ 1,012,245	$ 412,815	$ 1,266,720	$ 4,520,999	$ 593,911		
TOTAL	$ 737,325,000	$ 39,150,000	$ 68,350,028	$131,981,175	$ 53,824,725	$ 165,160,800	$ 458,466,728	$ 233,394,581		

Table 8 WGD Auburn 60kV Project Cost

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement	Levilized income
0	$ 55,000,000	$ 1,833,333	$ 5,098,500	$ 9,845,000	$ 4,015,000	$ 12,320,000	$ 33,111,833	$ 30,945,639	$ 22,947,693	$ 3,441,711
1	$ 53,166,667	$ 1,833,333	$ 4,928,550	$ 9,516,833	$ 3,881,167	$ 11,909,333	$ 32,069,217	$ 28,010,496		
2	$ 51,333,333	$ 1,833,333	$ 4,758,600	$ 9,188,667	$ 3,747,333	$ 11,498,667	$ 31,026,600	$ 25,326,948		
3	$ 49,500,000	$ 1,833,333	$ 4,588,650	$ 8,860,500	$ 3,613,500	$ 11,088,000	$ 29,983,983	$ 22,874,637		
4	$ 47,666,667	$ 1,833,333	$ 4,418,700	$ 8,532,333	$ 3,479,667	$ 10,677,333	$ 28,941,367	$ 20,634,794		
5	$ 45,833,333	$ 1,833,333	$ 4,248,750	$ 8,204,167	$ 3,345,833	$ 10,266,667	$ 27,898,750	$ 18,590,115		
6	$ 44,000,000	$ 1,833,333	$ 4,078,800	$ 7,876,000	$ 3,212,000	$ 9,856,000	$ 26,856,133	$ 16,724,650		
7	$ 42,166,667	$ 1,833,333	$ 3,908,850	$ 7,547,833	$ 3,078,167	$ 9,445,333	$ 25,813,517	$ 15,023,702		
8	$ 40,333,333	$ 1,833,333	$ 3,738,900	$ 7,219,667	$ 2,944,333	$ 9,034,667	$ 24,770,900	$ 13,473,728		
9	$ 38,500,000	$ 1,833,333	$ 3,568,950	$ 6,891,500	$ 2,810,500	$ 8,624,000	$ 23,728,283	$ 12,062,256		
10	$ 36,666,667	$ 1,833,333	$ 3,399,000	$ 6,563,333	$ 2,676,667	$ 8,213,333	$ 22,685,667	$ 10,777,797		
11	$ 34,833,333	$ 1,833,333	$ 3,229,050	$ 6,235,167	$ 2,542,833	$ 7,802,667	$ 21,643,050	$ 9,609,773		
12	$ 33,000,000	$ 1,833,333	$ 3,059,100	$ 5,907,000	$ 2,409,000	$ 7,392,000	$ 20,600,433	$ 8,548,447		
13	$ 31,166,667	$ 1,833,333	$ 2,889,150	$ 5,578,833	$ 2,275,167	$ 6,981,333	$ 19,557,817	$ 7,584,858		
14	$ 29,333,333	$ 1,833,333	$ 2,719,200	$ 5,250,667	$ 2,141,333	$ 6,570,667	$ 18,515,200	$ 6,710,761		
15	$ 27,500,000	$ 1,833,333	$ 2,549,250	$ 4,922,500	$ 2,007,500	$ 6,160,000	$ 17,472,583	$ 5,918,568		
16	$ 25,666,667	$ 1,833,333	$ 2,379,300	$ 4,594,333	$ 1,873,667	$ 5,749,333	$ 16,429,967	$ 5,201,307		
17	$ 23,833,333	$ 1,833,333	$ 2,209,350	$ 4,266,167	$ 1,739,833	$ 5,338,667	$ 15,387,350	$ 4,552,562		
18	$ 22,000,000	$ 1,833,333	$ 2,039,400	$ 3,938,000	$ 1,606,000	$ 4,928,000	$ 14,344,733	$ 3,966,438		
19	$ 20.166,667	$ 1,833,333	$ 1,869,450	$ 3,609,833	$ 1,472,167	$ 4,517,333	$ 13,302,117	$ 3,437,520		
20	$ 18,333,333	$ 1,833,333	$ 1,699,500	$ 3,281,667	$ 1,338,333	$ 4,106,667	$ 12,259,500	$ 2,960,830		
21	$ 16,500,000	$ 1,833,333	$ 1,529,550	$ 2,953,500	$ 1,204,500	$ 3,696,000	$ 11,216,883	$ 2,531,798		
22	$ 14,666,667	$ 1,833,333	$ 1,359,600	$ 2,625,333	$ 1,070,667	$ 3,285,333	$ 10,174,267	$ 2,146,230		
23	$ 12,833,333	$ 1,833,333	$ 1,189,650	$ 2,297,167	$ 936,833	$ 2,874,667	$ 9,131,650	$ 1,800,274		
24	$ 11,000,000	$ 1,833,333	$ 1,019,700	$ 1,969,000	$ 803,000	$ 2,464,000	$ 8,089,033	$ 1,490,398		
25	$ 9,166,667	$ 1,833,333	$ 849,750	$ 1,640,833	$ 669,167	$ 2,053,333	$ 7,046,417	$ 1,213,361		
26	$ 7,333,333	$ 1,833,333	$ 679,800	$ 1,312,667	$ 535,333	$ 1,642,667	$ 6,003,800	$ 966,194		
27	$ 5,500,000	$ 1,833,333	$ 509,850	$ 984,500	$ 401,500	$ 1,232,000	$ 4,961,183	$ 746,173		
28	$ 3,666,667	$ 1,833,333	$ 339,900	$ 656,333	$ 267,667	$ 821,333	$ 3,918,567	$ 550,805		
29	$ 1,833,333	$ 1,833,333	$ 169,950	$ 328,167	$ 133,833	$ 410,667	$ 2,875,950	$ 377,805		
TOTAL	$ 852,500,000	$ 55,000,000	$ 79,026,750	$152,597,500	$ 62,232,500	$ 190,960,000	$ 539,816,750	$ 284,758,864		

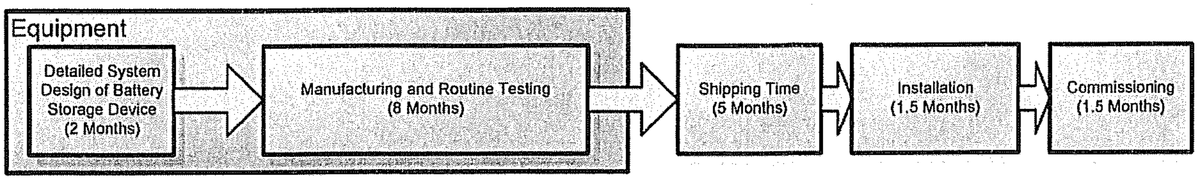
Table 9: PG&E Alternative Project Cost

Power Quality & Reliability Services	PV	
$ (2,099,272)	0.934579439	$ (1,961,937)
$ (2,099,272)	0.873438728	$ (1,833,586)
$ (2,099,272)	0.816297877	$ (1,713,631)
$ (2,099,272)	0.762895212	$ (1,601,525)
$ (2,099,272)	0.712986179	$ (1,496,752)
$ (2,099,272)	0.666342224	$ (1,398,834)
$ (2,099,272)	0.622749742	$ (1,307,321)
$ (2,099,272)	0.582009105	$ (1,221,796)
$ (2,099,272)	0.543933743	$ (1,141,865)
$ (2,099,272)	0.508349292	$ (1,067,164)
$ (2,099,272)	0.475092796	$ (997,349)
$ (2,099,272)	0.444011959	$ (932,102)
$ (2,099,272)	0.414964448	$ (871,123)
$ (2,099,272)	0.387817241	$ (814,134)
$ (2,099,272)	0.36244602	$ (760,873)
$ (2,099,272)	0.338734598	$ (711,096)
$ (2,099,272)	0.31657439	$ (664,576)
$ (2,099,272)	0.295863916	$ (621,099)
$ (2,099,272)	0.276508333	$ (580,466)
$ (2,099,272)	0.258419003	$ (542,492)
$ (2,099,272)	0.241513087	$ (507,002)
$ (2,099,272)	0.225713165	$ (473,833)
$ (2,099,272)	0.210946883	$ (442,835)
$ (2,099,272)	0.19714662	$ (413,864)
$ (2,099,272)	0.184249178	$ (386,789)
$ (2,099,272)	0.172195493	$ (361,485)
$ (2,099,272)	0.160930367	$ (337,837)
$ (2,099,272)	0.150402212	$ (315,735)
$ (2,099,272)	0.140562815	$ (295,080)
$ (2,099,272)	0.131367117	$ (275,775)
	TOTAL	-$26,049,956

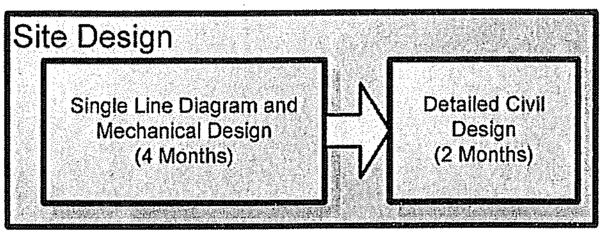
Table 10: Power Quality & Reliability Services Benefits

Construction schedule and expected online date:

The chart below outlines the estimated schedule of 18 months



During the 10 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Technical Data

The following pieces of technical information are attached to this application:

- Network model for power flow study in GE-PSLF format
    - Auburn.epc
- GE PSLF Batt model and model parameters
    - PSLF_batt_Model.pdf
    - BATT_epcl_parameters.xls
- Sample one line diagram
    - NAS Battery System SLD.pdf

Miscellaneous Data

Proposed entity to construct, own, and finance the project

Western Grid Development, LLC (WGD) will own the storage device project and will act as project manager during construction. WGD will also be responsible for financing the project.

Planned operator of the project

WGD will file to become a PTO under the CAISO tariff and will operate the project upon completion.

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the attachment A (technical data) to the CAISO contact listed in section 3. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to be considered in the CAISO Transmission Plan. This submission is for (check one)[1]:

   - ☒ Reliability Transmission Project (refer to section 1 of attachment A)
   - ☐ Merchant Transmission Facility (refer to section 1 of attachment A)
   - ☐ Economic Transmission Project (refer to section 1 of attachment A)
   - ☐ Location Constrained Resource Interconnection Facility (LCRIF) (refer to sections 1 & 2 of attachment A)
   - ☐ Project to preserve Long-term Congestion Revenue Rights (CRR) (refer to section 1 of attachment A)
   - ☐ Economic Planning Study Request (refer to section 3 of attachment A)
   - ☐ Others (refer to section 4 of attachment A)

2. For the submission of a Reliability, Merchant, Economic, LCRIF, and CRR project, the project sponsor is

   - ☒ Seeking ISO approval in this planning cycle
   - ☐ Submitting for information only (not requiring ISO approval in this planning cycle)

3. Please provide the following basic information about this submission:

   a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

      Project Name: **Potrero 115kV Energy Storage Project**

      Submission Date: **November 30, 2009**

   b. Project locations or the proposed interconnection point(s) :

      PG&E's Potrero 115kV Substation

   c. Project capacity (Net MW):

      20MW

   d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project e.g. overall scope, objectives etc.

The ability to reliably provide electricity to the San Francisco Peninsula Area is based on three critical "load serving" conditions:

[1] Please contact the ISO staff at requestwindow@caiso.com for any questions regarding the definitions of these submission categories in this form to the ISO

1) There is sufficient power to serve the electric needs of customers in the local areas;
2) The transmission system is capable of delivering that power to the local area where it is distributed to customers;
3) Power System operators can perform routine equipment maintenance and continue to reliably serve customers even after certain equipment failures occur;

Following a wide-spread outage in 1998 within San Francisco and the Peninsula, the San Francisco Stakeholder Study Group (SFSSG) was formed to develop an "Action Plan" to provide a plan to ensure reliable long-term load-serving. A key outcome from the group was the recommendation to install the Jefferson-Martin 230 kV Line Project, which was approved in 2002. This project added approximately 400 MW of load serving capability to the San Francisco-Peninsula region. The project became operational in April 2006. An unexpected outage of the 210 MW Potrero Unit #3 in November of 2006 and again in January 2007 illustrates this situation where reliance was placed on the Potrero Combustion Turbine units (CT's) to be available on short notice when needed. These CT's have not been as reliable as required and they are only permitted for 870 (10% of the year) hours. The action plan to release Potrero generation from RMR contracts identifies the transmission and generation infrastructure necessary to meet the applicable national, regional, and ISO reliability standards. A new High Voltage Direct Current line (DC Cable) capable of carrying 400 MW has been proposed by Trans Bay Cable and is planned to be in service by March 2010.

According to the CAISO, Potrero 3 will be shut down when the Trans Bay Cable becomes operational. The LCR requirements for San Francisco are 25 MW in 2010, 15 MW in 2011, and 10 MW in 2013. WGD is proposing a clean, innovative alternative to supply San Francisco with the needed capacity and energy to endure reliability of the area.

It was determined that approximately 20MW of battery storage would be required in 2011 to displace 10 MW LCR requirement. The additional 10MW was added to account for different assumptions in the San Francisco load growth. The storage device could also be used for multiple years in lieu of other projects. The study was done by reproducing the 2010 LCR study case showing the max line flow with TransBay Cable and A-H-W #1 115kV cable out of service. The storage device size was chosen based on the 2011 – 2013 LCR study. An energy storage device was then added to the Potrero 115kV bus and Potrero was taken offline.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**12 / 30 / 2010**
Proposed Trial Operation date:	**12 / 30 / 2010**
Proposed Commercial Operation date:	**12 / 30 / 2010**
Proposed Term of Service:	**30 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member**
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**

City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**917-282-0658**
Fax Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**

9. Technical Data (set forth in Attachment A).

☒ Is attached to this Request
☐ Will be provided at a later date

4. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Young
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

5. This Request is submitted by: **Western Grid Development, LLC**

Name of the Customer:	**Western Grid Development, LLC**
By (signature):	John Dizard
Name (type or print):	**John Dizard**
Title:	Managing Member
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**
Zip Code:	**10128**
Phone Number:	**212-937-4622**
Email Address:	**dizard@gmail.com**
Date:	**November 30, 2009**

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

This section applies to all transmission project submissions. It does not apply to Economic Planning Study Requests.

Any transmission project, including those seeking cost recovery through Long-term Congestion Revenue Rights, whether submitted by a PTO, non-PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[2]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route

Technical Data

- Network model for power flow study in GE-PSLF format. In some cases, Dynamic models for stability study in GE-PSLF format may also be required

Planning Level Cost Data[3]

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[2] This appendix lists the minimum amount of data required by the ISO for the first screening purposes. Additional data may be requested by the ISO later during the course of project evaluation

[3] Not required for Merchant Transmission Facilities

2. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets applicable reliability requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

3. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives, must be provided to CAISO by the closing date of Request Window.

4. Submission under "Other" category

This category of submission includes other type of proposals that may be considered as alternatives in the transmission planning process such as generation, demand response programs, new technologies etc. However, the ISO encourages project sponsors to contact CAISO staff prior to submitting these proposals through the Request Window.

General Data

Description of Project

Please see the attached report which includes a full reliability analysis and economic analysis on all WGD proposed projects.

Background:
The ability to reliably provide electricity to the San Francisco Peninsula Area is based on three critical "load serving" conditions:

1) There is sufficient power to serve the electric needs of customers in the local areas;
2) The transmission system is capable of delivering that power to the local area where it is distributed to customers;
3) Power System operators can perform routine equipment maintenance and continue to reliably serve customers even after certain equipment failures occur;

Following a wide-spread outage in 1998 within San Francisco and the Peninsula, the San Francisco Stakeholder Study Group (SFSSG) was formed to develop an "Action Plan" to provide a plan to ensure reliable long-term load-serving. A key outcome from the group was the recommendation to install the Jefferson-Martin 230 kV Line Project, which was approved in 2002. This project added approximately 400 MW of load serving capability to the San Francisco-Peninsula region. The project became operational in April 2006. An unexpected outage of the 210 MW Potrero Unit #3 in November of 2006 and again in January 2007 illustrates this situation where reliance was placed on the Potrero Combustion Turbine units (CT's) to be available on short notice when needed. These CT's have not been as reliable as required and they are only permitted for 870 (10% of the year) hours. The action plan to release Potrero generation from RMR contracts identifies the transmission and generation infrastructure necessary to meet the applicable national, regional, and ISO reliability standards. A new High Voltage Direct Current line (DC Cable) capable of carrying 400 MW has been proposed by Trans Bay Cable and is planned to be in service by March 2010.

According to the CAISO, Potrero 3 will be shut down when the Trans Bay Cable becomes operational. The LCR requirements for San Francisco are 25 MW in 2010, 15 MW in 2011, and 10 MW in 2013. WGD is proposing a clean, innovative alternative to supply San Francisco with the needed capacity and energy to endure reliability of the area.

Required Storage Device Size

The CAISO load flow study was reproduced using the 2010 CAISO LCR case. The base case was tuned to show the element at its emergency rating with the loss of TransBay Cable and A-H-W #1 115kV cable. The tuned results can be seen in Figure 1 below.

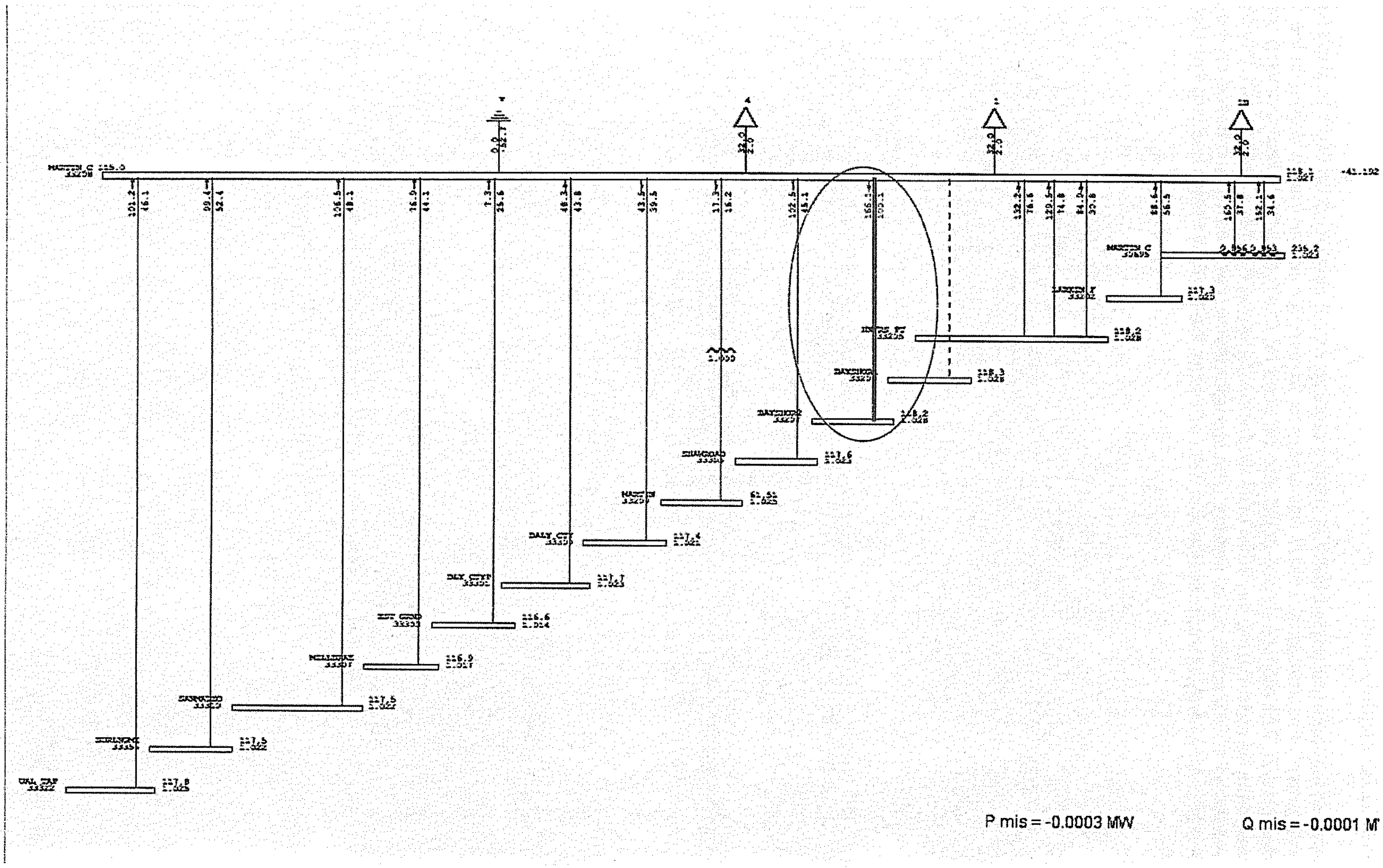


Figure 1: Tuned Potrero Results

It was determined that approximately 20MW of battery storage would be required in 2011 to displace 10 MW LCR requirement. The additional 10MW was added to account for different assumptions in the San Francisco load growth. The storage device could also be used for multiple years in lieu of other projects. The study was done by reproducing the 2010 LCR study case showing the max line flow with TransBay Cable and A-H-W #1 115kV cable out of service. The storage device size was chosen based on the 2011 – 2013 LCR study. An energy storage device was then added to the Potrero 115kV bus and Potrero was taken offline.

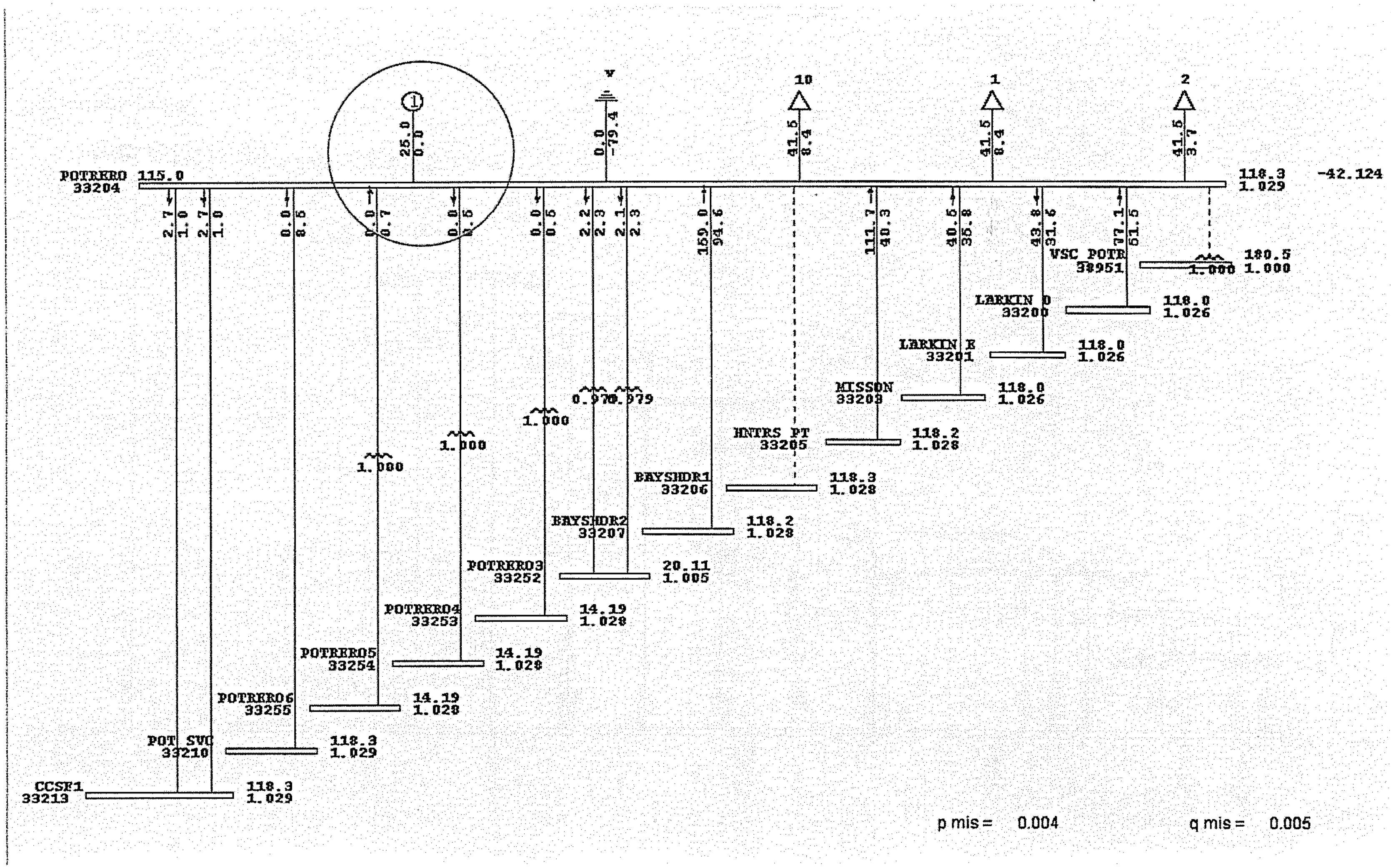


Figure 2: Tuned Results (Base Case)

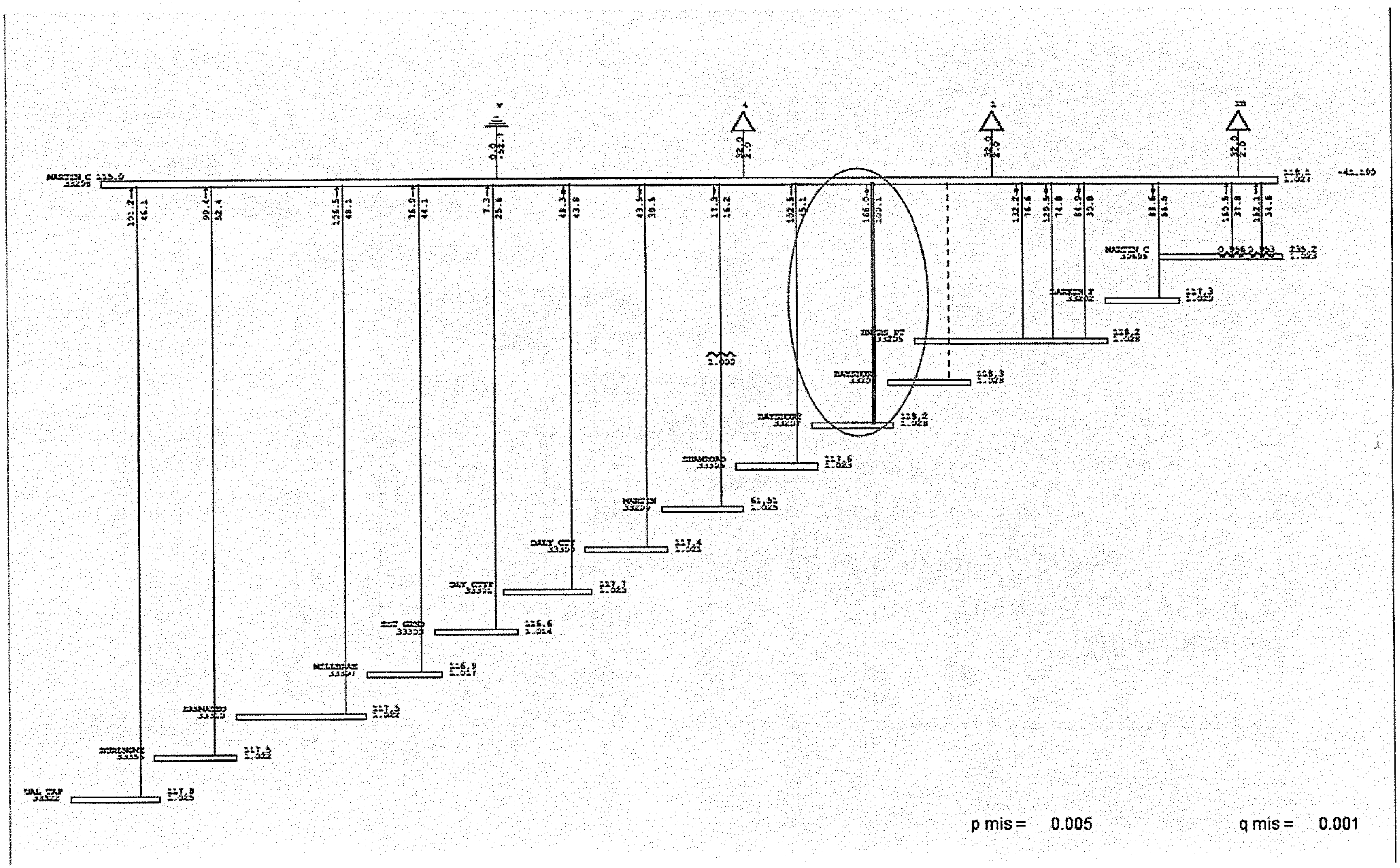


Figure 3: Tuned Results

Economic Analysis

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

WGD proposes using a service life of 30 years. Table 1 below shows the WGD ratemaking assumptions.

Assumption	Value	Pre-Calculations
n = Asset Life (Years)	30	-
Salvage Value ($)	$3,000,000.0	10%
Capital Cost ($)	$30,000,000.0	20MW*$1.5M
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$900,000.00
O&M = Operations and Maintanance	17.9%	-
A&G = Administrative and General	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 1: WGD Ratemaking Assumptions

Assumption	Value	Pre-Calculations
(Years)	30	-
Salvage Value	$0.0	-
Capital Cost ($)	$29,000,000.0	-
[illegible]	-	$966,666.67
O&M =	17.9%	-
A&G =	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 2: Alternative Rate Making Assumptions

Using the assumptions listed above, our analysis indicates that the WGD solution has a levelized annual revenue requirement of $12.1M compared to $12.1M for the alternative peaker project. The overall project cost was calculated at $149.8M NPV compared to $150.1M NPV for the alternative peaker project with an additional $18.0M in Power Quality and Reliability Services. The alternative peaker project to WGD cost ratio is 1.12% indicating a large economic benefit as the WGD project is 12% less expensive than the alternative peaker project solution.

Year (n)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Power Quality & Reliability Services	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 30,000,000	$ 900,000	$ 2,781,000	$ 5,370,000	$ 2,190,000	$ 6,720,000	$ (1,447,774)	$ 17,061,000	$ 15,944,850	$ 12,071,331
1	$ 29,100,000	$ 900,000	$ 2,697,570	$ 5,208,900	$ 2,124,300	$ 6,518,400	$ (1,447,774)	$ 16,549,170	$ 14,454,686	
2	$ 28,200,000	$ 900,000	$ 2,614,140	$ 5,047,800	$ 2,058,600	$ 6,316,800	$ (1,447,774)	$ 16,037,340	$ 13,091,247	
3	$ 27,300,000	$ 900,000	$ 2,530,710	$ 4,886,700	$ 1,992,900	$ 6,115,200	$ (1,447,774)	$ 15,525,510	$ 11,844,337	
4	$ 26,400,000	$ 900,000	$ 2,447,280	$ 4,725,600	$ 1,927,200	$ 5,913,600	$ (1,447,774)	$ 15,013,680	$ 10,704,546	
5	$ 25,500,000	$ 900,000	$ 2,363,850	$ 4,564,500	$ 1,861,500	$ 5,712,000	$ (1,447,774)	$ 14,501,850	$ 9,663,195	
6	$ 24,600,000	$ 900,000	$ 2,280,420	$ 4,403,400	$ 1,795,800	$ 5,510,400	$ (1,447,774)	$ 13,990,020	$ 8,712,281	
7	$ 23,700,000	$ 900,000	$ 2,196,990	$ 4,242,300	$ 1,730,100	$ 5,308,800	$ (1,447,774)	$ 13,478,190	$ 7,844,429	
8	$ 22,800,000	$ 900,000	$ 2,113,560	$ 4,081,200	$ 1,664,400	$ 5,107,200	$ (1,447,774)	$ 12,966,360	$ 7,052,841	
9	$ 21,900,000	$ 900,000	$ 2,030,130	$ 3,920,100	$ 1,598,700	$ 4,905,600	$ (1,447,774)	$ 12,454,530	$ 6,331,252	
10	$ 21,000,000	$ 900,000	$ 1,946,700	$ 3,759,000	$ 1,533,000	$ 4,704,000	$ (1,447,774)	$ 11,942,700	$ 5,673,891	
11	$ 20,100,000	$ 900,000	$ 1,863,270	$ 3,597,900	$ 1,467,300	$ 4,502,400	$ (1,447,774)	$ 11,430,870	$ 5,075,443	
12	$ 19,200,000	$ 900,000	$ 1,779,840	$ 3,436,800	$ 1,401,600	$ 4,300,800	$ (1,447,774)	$ 10,919,040	$ 4,531,013	
13	$ 18,300,000	$ 900,000	$ 1,696,410	$ 3,275,700	$ 1,335,900	$ 4,099,200	$ (1,447,774)	$ 10,407,210	$ 4,036,095	
14	$ 17,400,000	$ 900,000	$ 1,612,980	$ 3,114,600	$ 1,270,200	$ 3,897,600	$ (1,447,774)	$ 9,895,380	$ 3,586,541	
15	$ 16,500,000	$ 900,000	$ 1,529,550	$ 2,953,500	$ 1,204,500	$ 3,696,000	$ (1,447,774)	$ 9,383,550	$ 3,178,533	
16	$ 15,600,000	$ 900,000	$ 1,446,120	$ 2,792,400	$ 1,138,800	$ 3,494,400	$ (1,447,774)	$ 8,871,720	$ 2,808,559	
17	$ 14,700,000	$ 900,000	$ 1,362,690	$ 2,631,300	$ 1,073,100	$ 3,292,800	$ (1,447,774)	$ 8,359,890	$ 2,473,390	
18	$ 13,800,000	$ 900,000	$ 1,279,260	$ 2,470,200	$ 1,007,400	$ 3,091,200	$ (1,447,774)	$ 7,848,060	$ 2,170,054	
19	$ 12,900,000	$ 900,000	$ 1,195,830	$ 2,309,100	$ 941,700	$ 2,889,600	$ (1,447,774)	$ 7,336,230	$ 1,896,821	
20	$ 12,000,000	$ 900,000	$ 1,112,400	$ 2,148,000	$ 876,000	$ 2,688,000	$ (1,447,774)	$ 6,824,400	$ 1,648,182	
21	$ 11,100,000	$ 900,000	$ 1,028,970	$ 1,986,900	$ 810,300	$ 2,486,400	$ (1,447,774)	$ 6,312,570	$ 1,424,830	
22	$ 10,200,000	$ 900,000	$ 945,540	$ 1,825,800	$ 744,600	$ 2,284,800	$ (1,447,774)	$ 5,800,740	$ 1,223,648	
23	$ 9,300,000	$ 900,000	$ 862,110	$ 1,664,700	$ 678,900	$ 2,083,200	$ (1,447,774)	$ 5,288,910	$ 1,042,691	
24	$ 8,400,000	$ 900,000	$ 778,680	$ 1,503,600	$ 613,200	$ 1,881,600	$ (1,447,774)	$ 4,777,080	$ 880,173	
25	$ 7,500,000	$ 900,000	$ 695,250	$ 1,342,500	$ 547,500	$ 1,680,000	$ (1,447,774)	$ 4,265,250	$ 734,457	
26	$ 6,600,000	$ 900,000	$ 611,820	$ 1,181,400	$ 481,800	$ 1,478,400	$ (1,447,774)	$ 3,753,420	$ 604,039	
27	$ 5,700,000	$ 900,000	$ 528,390	$ 1,020,300	$ 416,100	$ 1,276,800	$ (1,447,774)	$ 3,241,590	$ 487,542	
28	$ 4,800,000	$ 900,000	$ 444,960	$ 859,200	$ 350,400	$ 1,075,200	$ (1,447,774)	$ 2,729,760	$ 383,703	
29	$ 3,900,000	$ 900,000	$ 361,530	$ 698,100	$ 284,700	$ 873,600	$ (1,447,774)	$ 2,217,930	$ 291,363	
TOTAL	$ 508,500,000	$ 27,000,000	$ 47,137,950	$ 91,021,500	$ 37,120,500	$ 113,904,000	$ (43,433,219)	$ 316,183,950	$ 149,793,643	

Table 3: WGD Project Cost Alternatives

Year (n)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 29,000,000	$ 966,667	$ 2,688,300	$ 5,191,000	$ 2,117,000	$ 6,496,000	$ 17,450,967	$ 16,316,791	$ 12,099,693
1	$ 28,033,333	$ 966,667	$ 2,598,690	$ 5,017,967	$ 2,046,433	$ 6,279,467	$ 16,909,223	$ 14,769,171	
2	$ 27,066,667	$ 966,667	$ 2,509,080	$ 4,844,933	$ 1,975,867	$ 6,062,933	$ 16,359,480	$ 13,354,209	
3	$ 26,100,000	$ 966,667	$ 2,419,470	$ 4,671,900	$ 1,905,300	$ 5,846,400	$ 15,809,737	$ 12,091,172	
4	$ 25,133,333	$ 966,667	$ 2,329,860	$ 4,498,867	$ 1,834,733	$ 5,629,867	$ 15,259,993	$ 10,880,164	
5	$ 24,166,667	$ 966,667	$ 2,240,250	$ 4,325,833	$ 1,764,167	$ 5,413,333	$ 14,710,250	$ 9,802,061	
6	$ 23,200,000	$ 966,667	$ 2,150,640	$ 4,152,800	$ 1,693,600	$ 5,196,800	$ 14,160,507	$ 8,818,452	
7	$ 22,233,333	$ 966,667	$ 2,061,030	$ 3,979,767	$ 1,623,033	$ 4,980,267	$ 13,610,763	$ 7,921,568	
8	$ 21,266,667	$ 966,667	$ 1,971,420	$ 3,806,733	$ 1,552,467	$ 4,763,733	$ 13,061,020	$ 7,104,329	
9	$ 20,300,000	$ 966,667	$ 1,881,810	$ 3,633,700	$ 1,481,900	$ 4,547,200	$ 12,511,277	$ 6,360,099	
10	$ 19,333,333	$ 966,667	$ 1,792,200	$ 3,460,667	$ 1,411,333	$ 4,330,667	$ 11,961,533	$ 5,682,838	
11	$ 18,366,667	$ 966,667	$ 1,702,590	$ 3,287,633	$ 1,340,767	$ 4,114,133	$ 11,411,790	$ 5,066,971	
12	$ 17,400,000	$ 966,667	$ 1,612,980	$ 3,114,600	$ 1,270,200	$ 3,897,600	$ 10,862,047	$ 4,507,363	
13	$ 16,433,333	$ 966,667	$ 1,523,370	$ 2,941,567	$ 1,199,633	$ 3,681,067	$ 10,312,303	$ 3,999,289	
14	$ 15,466,667	$ 966,667	$ 1,433,760	$ 2,768,533	$ 1,129,067	$ 3,464,533	$ 9,762,560	$ 3,538,401	
15	$ 14,500,000	$ 966,667	$ 1,344,150	$ 2,595,500	$ 1,058,500	$ 3,248,000	$ 9,212,817	$ 3,120,700	
16	$ 13,533,333	$ 966,667	$ 1,254,540	$ 2,422,467	$ 987,933	$ 3,031,467	$ 8,663,073	$ 2,742,507	
17	$ 12,566,667	$ 966,667	$ 1,164,930	$ 2,249,433	$ 917,367	$ 2,814,933	$ 8,113,330	$ 2,400,442	
18	$ 11,600,000	$ 966,667	$ 1,075,320	$ 2,076,400	$ 846,800	$ 2,598,400	$ 7,563,587	$ 2,091,395	
19	$ 10,633,333	$ 966,667	$ 985,710	$ 1,903,367	$ 776,233	$ 2,381,867	$ 7,013,843	$ 1,812,510	
20	$ 9,666,667	$ 966,667	$ 896,100	$ 1,730,333	$ 705,667	$ 2,165,333	$ 6,464,100	$ 1,561,165	
21	$ 8,700,000	$ 966,667	$ 806,490	$ 1,557,300	$ 635,100	$ 1,948,800	$ 5,914,357	$ 1,334,948	
22	$ 7,733,333	$ 966,667	$ 716,880	$ 1,384,267	$ 564,533	$ 1,732,267	$ 5,364,613	$ 1,131,648	
23	$ 6,766,667	$ 966,667	$ 627,270	$ 1,211,233	$ 493,967	$ 1,515,733	$ 4,814,870	$ 949,235	
24	$ 5,800,000	$ 966,667	$ 537,660	$ 1,038,200	$ 423,400	$ 1,299,200	$ 4,265,127	$ 785,646	
25	$ 4,833,333	$ 966,667	$ 448,050	$ 865,167	$ 352,833	$ 1,082,667	$ 3,715,383	$ 639,772	
26	$ 3,866,667	$ 966,667	$ 358,440	$ 692,133	$ 282,267	$ 866,133	$ 3,165,640	$ 509,446	
27	$ 2,900,000	$ 966,667	$ 268,830	$ 519,100	$ 211,700	$ 649,600	$ 2,615,897	$ 393,437	
28	$ 1,933,333	$ 966,667	$ 179,220	$ 346,067	$ 141,133	$ 433,067	$ 2,066,153	$ 290,424	
29	$ 966,667	$ 966,667	$ 89,610	$ 173,033	$ 70,567	$ 216,533	$ 1,516,410	$ 199,206	
TOTAL	$ 449,500,000	$ 29,000,000	$ 41,668,650	$ 80,460,500	$ 32,813,500	$ 100,688,000	$ 284,630,650	$ 150,145,583	

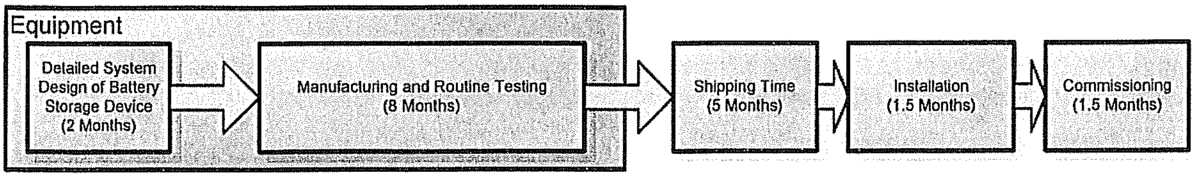
Table 4: Proposed Peaker

Power Quality & Reliability Services	PV	
$ (1,447,774)	0.934579439	$ (1,353,059.79)
$ (1,447,774)	0.873438728	$ (1,264,541.86)
$ (1,447,774)	0.816297877	$ (1,181,814.82)
$ (1,447,774)	0.762895212	$ (1,104,499.83)
$ (1,447,774)	0.712986179	$ (1,032,242.83)
$ (1,447,774)	0.666342224	$ (964,712.93)
$ (1,447,774)	0.622749742	$ (901,600.87)
$ (1,447,774)	0.582009105	$ (842,617.63)
$ (1,447,774)	0.543933743	$ (787,493.12)
$ (1,447,774)	0.508349292	$ (735,974.87)
$ (1,447,774)	0.475092796	$ (687,826.99)
$ (1,447,774)	0.444011959	$ (642,828.96)
$ (1,447,774)	0.414964448	$ (600,774.73)
$ (1,447,774)	0.387817241	$ (561,471.71)
$ (1,447,774)	0.36244602	$ (524,739.91)
$ (1,447,774)	0.338734598	$ (490,411.13)
$ (1,447,774)	0.31657439	$ (458,328.16)
$ (1,447,774)	0.295863916	$ (428,344.08)
$ (1,447,774)	0.276508333	$ (400,321.57)
$ (1,447,774)	0.258419003	$ (374,132.31)
$ (1,447,774)	0.241513087	$ (349,656.36)
$ (1,447,774)	0.225713165	$ (326,781.65)
$ (1,447,774)	0.210946883	$ (305,403.41)
$ (1,447,774)	0.19714662	$ (285,423.75)
$ (1,447,774)	0.184249178	$ (266,751.16)
$ (1,447,774)	0.172195493	$ (249,300.15)
$ (1,447,774)	0.160930367	$ (232,990.80)
$ (1,447,774)	0.150402212	$ (217,748.41)
$ (1,447,774)	0.140562815	$ (203,503.19)
$ (1,447,774)	0.131367117	$ (190,189.89)
		$ (17,965,487)

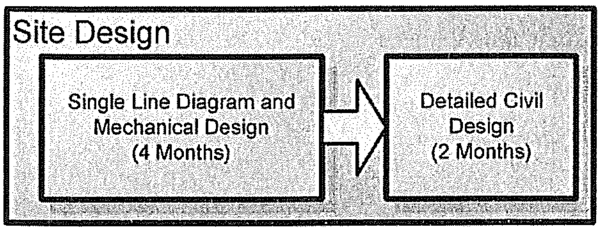
Table 5: Power Quality and Reliability Services Estimates

Construction schedule and expected online date:

The chart below outlines the estimated schedule of 18 months



During the 10 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Technical Data

The following pieces of technical information are attached to this application:

- Network model for power flow study in GE-PSLF format
  - potrero.epc
- GE PSLF Batt model and model parameters
  - PSLF_batt_Model.pdf
  - BATT_epcl_parameters.xls
- Sample one line diagram
  - NAS Battery System SLD.pdf

Miscellaneous Data

Proposed entity to construct, own, and finance the project

Western Grid Development, LLC (WGD) will own the storage device project and will act as project manager during construction. WGD will also be responsible for financing the project.

Planned operator of the project

WGD will file to become a PTO under the CAISO tariff and will operate the project upon completion.

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the attachment A (technical data) to the CAISO contact listed in section 3. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to be considered in the CAISO Transmission Plan. This submission is for (check one)[1]:

- ☒ Reliability Transmission Project (refer to section 1 of attachment A)
- ☐ Merchant Transmission Facility (refer to section 1 of attachment A)
- ☐ Economic Transmission Project (refer to section 1 of attachment A)
- ☐ Location Constrained Resource Interconnection Facility (LCRIF) (refer to sections 1 & 2 of attachment A)
- ☐ Project to preserve Long-term Congestion Revenue Rights (CRR) (refer to section 1 of attachment A)
- ☐ Economic Planning Study Request (refer to section 3 of attachment A)
- ☐ Others (refer to section 4 of attachment A)

2. For the submission of a Reliability, Merchant, Economic, LCRIF, and CRR project, the project sponsor is

- ☒ Seeking ISO approval in this planning cycle
- ☐ Submitting for information only (not requiring ISO approval in this planning cycle)

3. Please provide the following basic information about this submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Stockton 60kV Energy Storage Project**

Submission Date: **November 30, 2009**

b. Project locations or the proposed interconnection point(s) :

PG&E's Stockton A 60kV Substation

c. Project capacity (Net MW):

Initially 14MW of energy storage will be installed at the Stockton A 60kV substation. Additional storage will be added every 5 years to maintain system reliability and account for load growth. The table below outlines the amount of storage that is required from years 1-30.

[1] Please contact the ISO staff at requestwindow@caiso.com for any questions regarding the definitions of these submission categories in this form to the ISO

Stockton A	
Year	Storage Device Size (MW)
5	14
10	20
15	28
20	36
25	45
30	55

Table 1: Required Storage Device Size

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project e.g. overall scope, objectives etc.

The CAISO Reliability Assessment Results (September 15, 2009) for the Central Valley area identified that loss of the Stockton A-Weber #2 and Stockton Wastewater would cause the Stockton A-Weber #1 60kV line to overload to 107% of its emergency rating by 2014. The CAISO recommends a re-conductor of the line.

WGD is proposing a alternative solution which includes installing a 14MW battery storage device at the Stockton A 60kV substation in 2014, followed by six additional battery storage installations (one every 5 years) to account for load growth. This project will resolve reliability concerns for 30 years.

Economic analysis shows that the WGD solution has a levelized annual revenue requirement of $17M compared to $16.7M for the recommended Reconductor project. The overall project cost was calculated at $210.4M NPV compared to $207.1M NPV for recommended Reconductor project with an additional $23M in Power Quality and Reliability services. The recommended Reconductor project to WGD cost ratio is 1.09% indicating a large economic benefit as the WGD project is 9% less expensive than the recommended Reconductor project proposed solution.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**03 / 30 / 2014**
Proposed Trial Operation date:	**03 / 30 / 2014**
Proposed Commercial Operation date:	**03 / 30 / 2014**
Proposed Term of Service:	**30 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member**
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
CAISO TRANSMISSION PLANNING PROCESS
REQUEST WINDOW SUBMISSION FORM

Zip Code:	10128
Phone Number:	917-282-0658
Fax Number:	212-937-4622
Email Address:	dizard@gmail.com

g Technical Data (set forth in Attachment A)

☒ Is attached to this Request
☐ Will be provided at a later date

4. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Young
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

5. This Request is submitted by: Western Grid Development, LLC

Name of the Customer:	Western Grid Development, LLC
By (signature):	(John Dizard)
Name (type or print):	John Dizard
Title:	Managing Member
Company Name:	Western Grid Development, LLC
Street Address:	200 East 94th Street, Suite 2218
City, State:	New York, NY
Zip Code:	10128
Phone Number:	212-937-4622
Email Address:	dizard@gmail.com
Date:	November 30, 2009

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

This section applies to all transmission project submissions. It does not apply to Economic Planning Study Requests.

Any transmission project, including those seeking cost recovery through Long-term Congestion Revenue Rights, whether submitted by a PTO, non-PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[2]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route

Technical Data

- Network model for power flow study in GE-PSLF format. In some cases, Dynamic models for stability study in GE-PSLF format may also be required

Planning Level Cost Data[3]

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[2] This appendix lists the minimum amount of data required by the ISO for the first screening purposes. Additional data may be requested by the ISO later during the course of project evaluation

[3] Not required for Merchant Transmission Facilities

2. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets applicable reliability requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

3. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives, must be provided to CAISO by the closing date of Request Window.

4. Submission under "Other" category

This category of submission includes other type of proposals that may be considered as alternatives in the transmission planning process such as generation, demand response programs, new technologies etc. However, the ISO encourages project sponsors to contact CAISO staff prior to submitting these proposals through the Request Window.

General Data

Description of Project

Please see the attached report which includes a full reliability analysis and economic analysis on all WGD proposed projects.

The CAISO Reliability Assessment Results (September 15, 2009) for the Central Valley area identified that loss of the Stockton A-Weber #2 and Stockton Wastewater would cause the Stockton A-Weber #1 60kV line to overload to 107% of its emergency rating by 2014. The CAISO recommends a re-conductor of the line.

WGD is proposing a alternative solution which includes installing a 14MW battery storage device at the Stockton A 60kV substation in 2014, followed by six additional battery storage installations (one every 5 years) to account for load growth. This project will resolve reliability concerns for 30 years.

Economic analysis shows that the WGD solution has a levelized annual revenue requirement of $17M compared to $16.7M for the recommended Reconductor project. The overall project cost was calculated at $210.4M NPV compared to $207.1M NPV for recommended Reconductor project with an additional $23M in Power Quality and Reliability services. The recommended Reconductor project to WGD cost ratio is 1.09% indicating a large economic benefit as the WGD project is 9% less expensive than the recommended Reconductor project proposed solution.

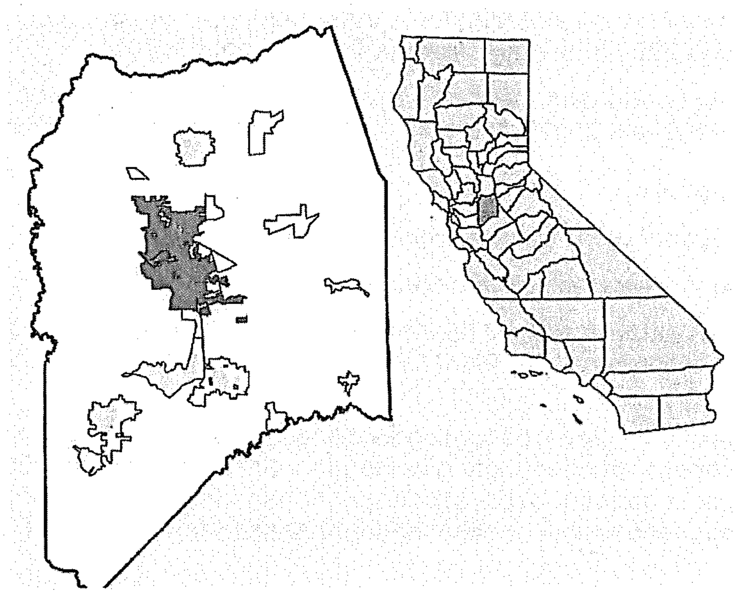


Figure 1: Stockton Geographic Location

Required Storage Device Size

A load flow study was performed using the WECC 2015 heavy summer base case. The WECC 2015 heavy summer base case was tuned to 2014 load values which according to CAISO studies would put the limiting element at 107% of its emergency rating by 2014. The tuned results can be seen in Figure 2 below.

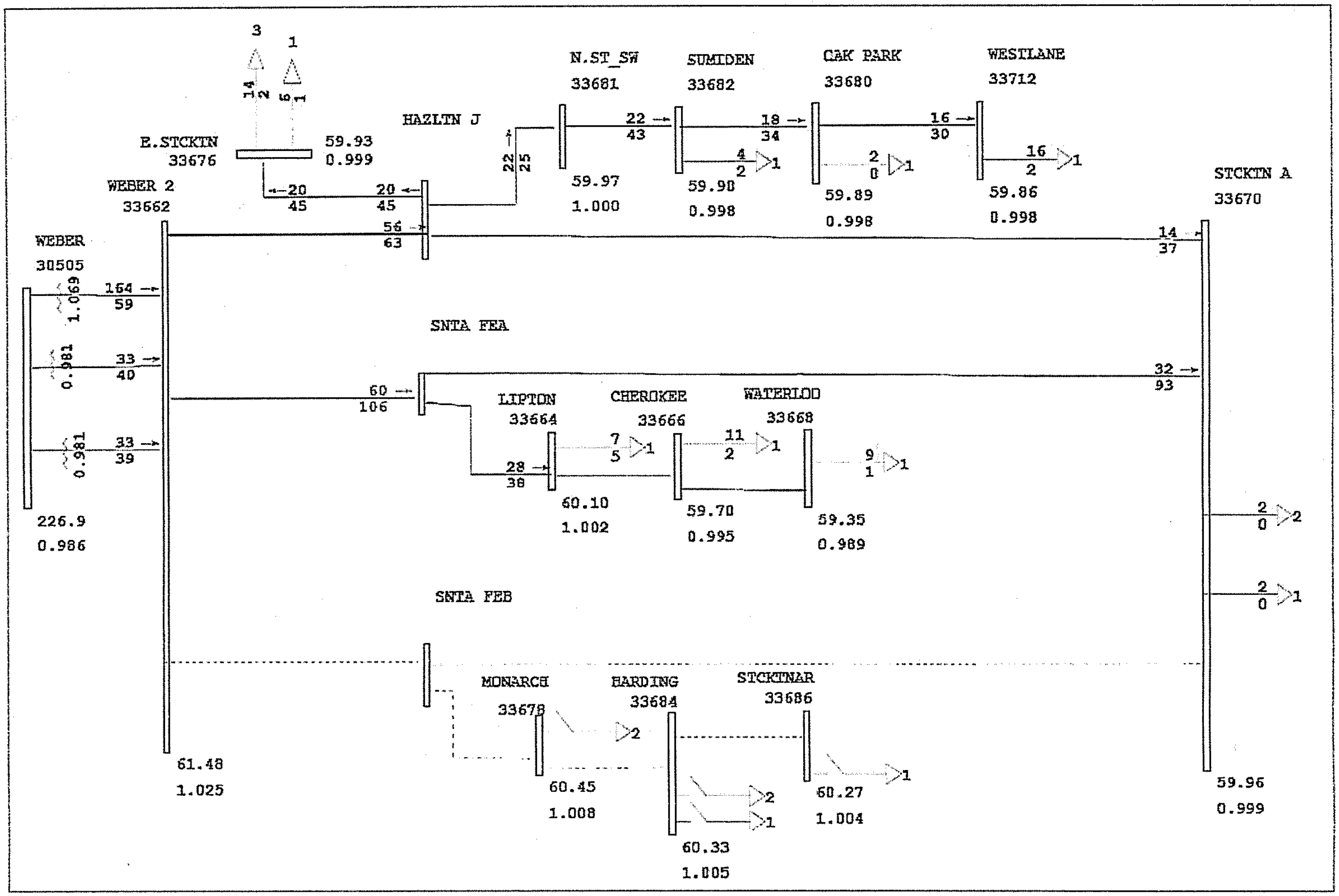


Figure 2: WECC 2014 Post Contingency Stockton A Flows

It was determined that approximately 14MW of battery storage would be required to keep post contingency line flows on the Stockton A-Weber #1 60kV line below its emergency rating for the loss of the Stockton A-Weber #2 60kV line. 14MW of storage would be installed in 2014, and this would be sufficient to keep the limiting element below 100% of its emergency rating until 2019. In 2019 additional battery storage will be installed to meet load levels for the next five years. This cycle will continue until enough batter storage is installed to cover a 30 year project life.

To avoid the line overload a 14MW battery storage device was placed at the Stockton A 60kV substation. Table 2 below shows the assumed 2019 load (5 year). Figure 3 shows the post contingency line flows after a storage device placed at the Stockton A 60kV substation.

Zone Number	Assumed 2014 Load (MW/MVAR)	5 year
311 - Conforming Load Stockton	1328	1416.6
	190	202.7
Total Load	1328.0	1416.6
Required Battery		14

Table 2 Projected Stockton 2019 Load

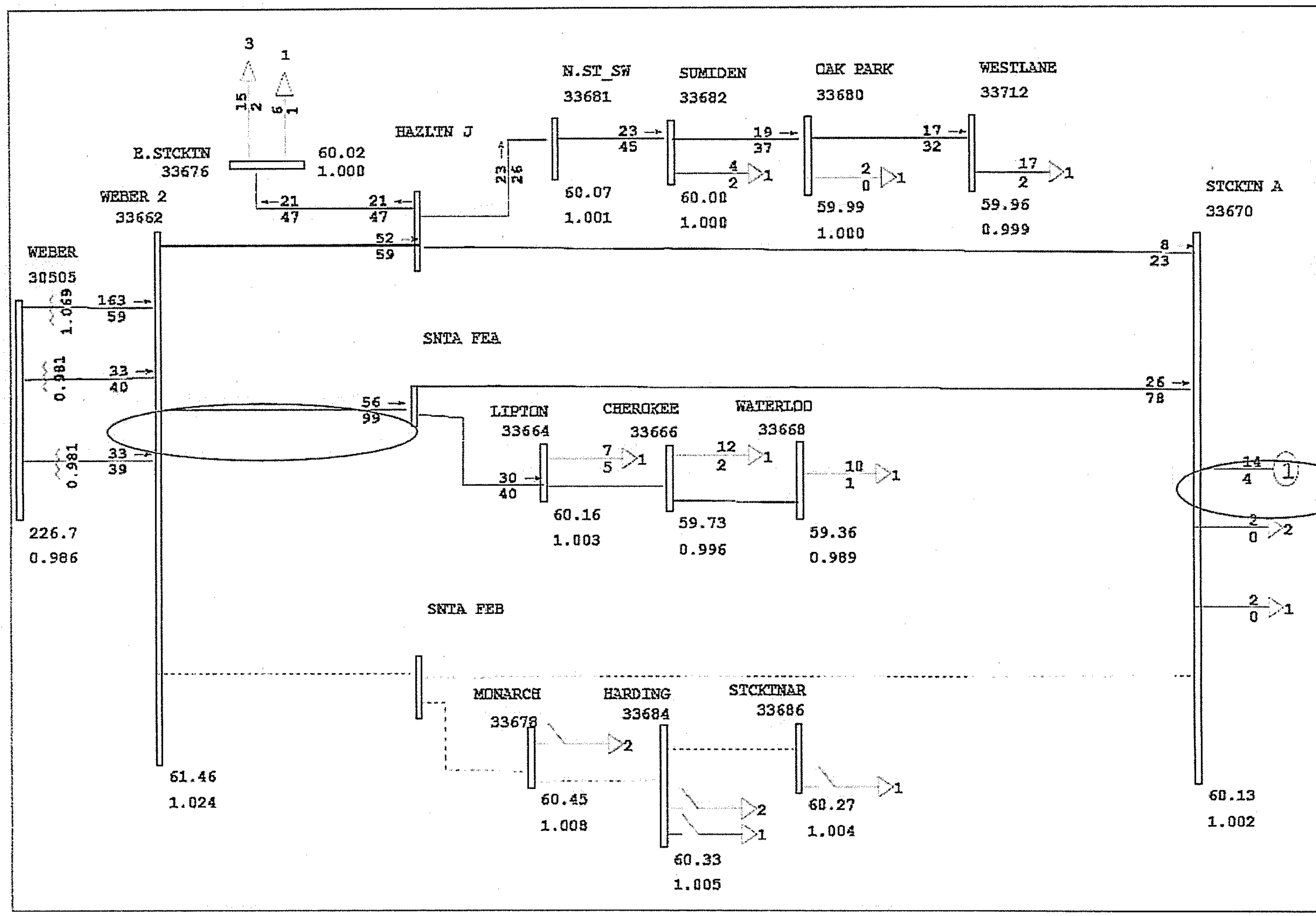


Figure 3: Stockton A 60 kV Pocket 2019 (5 Year) Projection

The next step involved calculating the required battery size for a 30 year load growth. The Stockton load was increased at a rate of 3% per year. This rate was found in the CEC Staff Final Energy Demand Forecast Report. In the report the CEC states that 1.3% is the forecasted average annual growth in load from 2008-2020 as shown below in table 3.

Business-as-Usual Reference Case						
Source: CEC Staff Final Energy Demand Forecast Report, October 2007						
Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	21,886	1.3%	81,532	95,598	1.3%
SCE	21,476	25,777	1.5%	87,966	106,018	1.6%
SDG&E	3,712	4,423	1.5%	18,687	22,651	1.6%
SMUD	3,174	3,741	1.4%	11,887	13,990	1.4%
LADWP	5,717	6,010	0.4%	28,004	29,592	0.5%
NorCalMunis	5,077	5,942	1.3%	35,720	39,440	0.8%
SoCalMunis	5,079	5,959	1.3%	35,148	38,276	0.7%
California	62,946	73,738	1.3%	298,945	345,566	1.2%

Table 3: CEC Energy Demand Forecast

It was found that a 55MW battery storage device at the Stockton A 60kV substation was required to keep limiting element below its emergency rating. The 2044 (30 year) Stockton load values are in table 4 below, along with the required battery storage sizes to accommodate the load growth.

Zone Number	Assumed 2014 Load (MW/MVAR)	5 year	10 Year	15 year	20 year	25 year	2044 Expected Values (30 Year)
311 - Conforming Load Stockton	1328	1416.6	1511.1	1611.9	1719.4	1834.1	1956.5
	190	202.7	216.2	230.6	246.0	262.4	279.9
Total Load	1328.0	1416.6	1511.1	1611.9	1719.4	1834.1	1956.5
Required Battery		14	20	28	36	45	55.0

Table 4: Projected 30 Year Storage Device Size

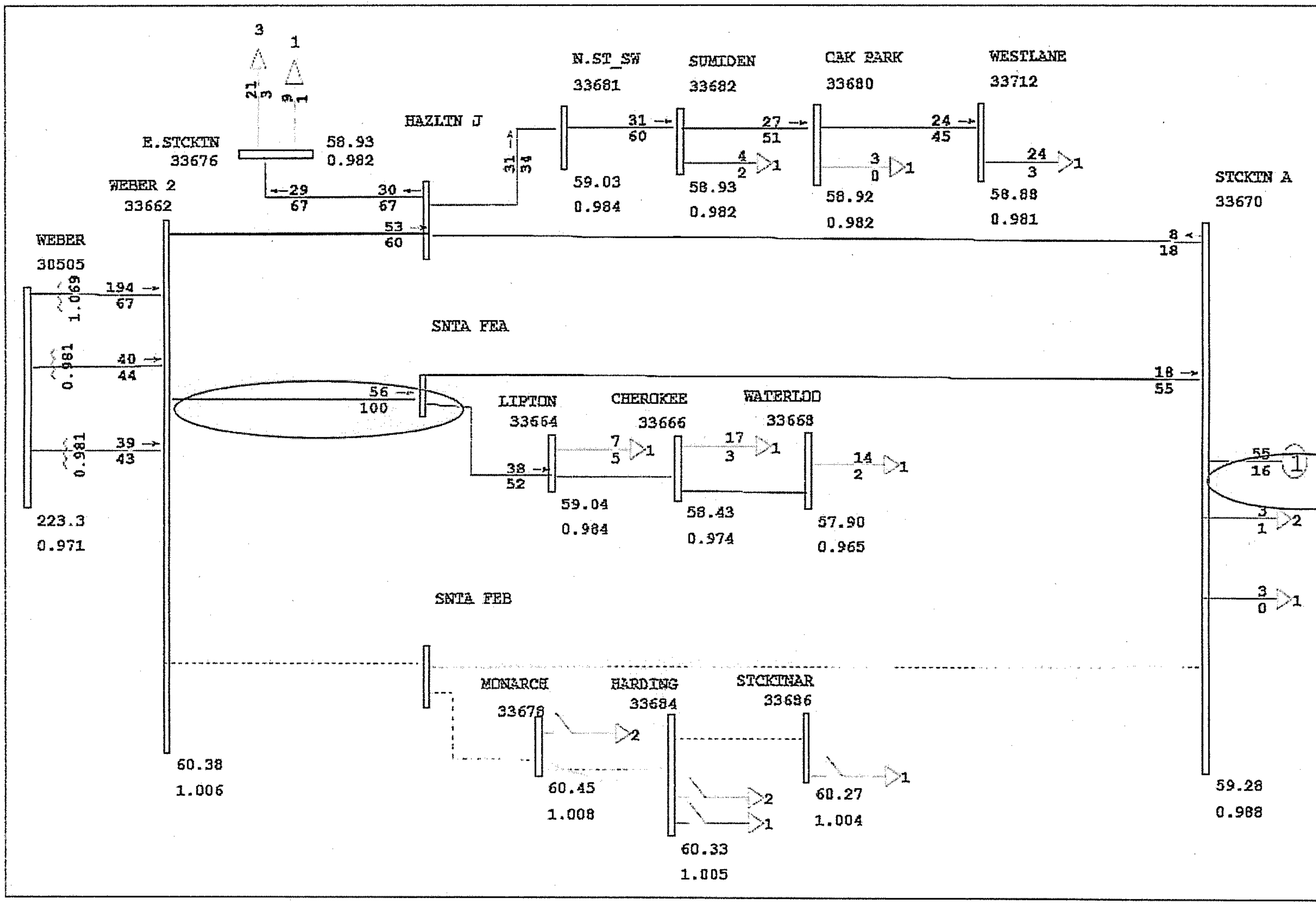


Figure 4: Stockton A 60kV Pocket 2044 (30 Year) Projection

Economic Analysis

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

WGD proposes using a service life of 30 years. Table 5 below shows the WGD ratemaking assumptions.

Install Date	Assumption	Value	Pre-Calculations	Note
	Battery Cost ($/MW)	$1,500,000.00		
Year 1	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$21,000,000.0	-	14MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$700,000.00	
Year 5	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$9,664,467.4	-	(14-20)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$322,148.91	
Year 10	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$10,860,480.9	-	(28-20)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$362,016.03	
Year 15	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$12,173,059.7	-	(36-28)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$405,768.66	
Year 20	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$13,612,433.8	-	(45-36)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$453,747.79	
Year 25	*n = Asset Life (Years)*	30	-	
	Salvage Value ($)	$0.0	-	
	Capital Cost ($)	$15,189,558.3	-	(55-45)MW*$1.5M.
	$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$506,318.61	
	O&M = Operations and Maintanance	17.9%	-	
	A&G = Administrative and General	7.30%	-	
	Cost of Capital	9.27%	-	
	Taxes	22.4%	-	
	i = Interest Rate	7.00%	-	

Table 5: WGD Ratemaking Assumptions

Assumption	Value	Pre-Calculations
n = Asset Life (Years)	30	-
Salvage Value ($)	$0.0	-
Capital Cost ($)	$40,000,000.0	-
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$1,333,333.33
O&M = Operations and Maintanance	17.9%	-
A&G = Administrative and General	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 6: Proposed Project Ratemaking Assumptions

Using the assumptions listed above, the WGD solution has a levelized annual revenue requirement of $17M compared to $16.7M for the recommended Reconductor project. The overall project cost was calculated at $210.4M NPV compared to $207.1M NPV for recommended Reconductor project with an additional $23M in Power Quality and Reliability services. The recommended Reconductor project to WGD cost ratio is 1.09% indicating a large economic benefit as the WGD project is 9% less expensive than the recommended Reconductor project proposed solution.

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Power Quality & Reliability Services	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 21,000,000	$ 700,000	$ 1,946,700	$ 3,759,000	$ 1,533,000	$ 4,704,000	$ (1,013,442)	$ 12,642,700	$ 11,815,607	$ 16,951,689
1	$ 20,300,000	$ 700,000	$ 1,881,810	$ 3,633,700	$ 1,481,900	$ 4,547,200	$ (1,013,442)	$ 12,244,610	$ 10,694,917	
2	$ 19,600,000	$ 700,000	$ 1,816,920	$ 3,508,400	$ 1,430,800	$ 4,390,400	$ (1,013,442)	$ 11,846,520	$ 9,670,289	
3	$ 18,900,000	$ 700,000	$ 1,752,030	$ 3,383,100	$ 1,379,700	$ 4,233,600	$ (1,013,442)	$ 11,448,430	$ 8,733,952	
4	$ 18,200,000	$ 700,000	$ 1,687,140	$ 3,257,800	$ 1,328,600	$ 4,076,800	$ (1,013,442)	$ 11,050,340	$ 7,878,740	
5	$ 27,164,467	$ 1,022,149	$ 2,518,146	$ 4,862,440	$ 1,983,006	$ 6,084,841	$ (1,479,841)	$ 16,470,582	$ 10,975,044	
6	$ 26,142,318	$ 1,022,149	$ 2,423,393	$ 4,679,475	$ 1,908,389	$ 5,855,879	$ (1,479,841)	$ 15,889,285	$ 9,895,048	
7	$ 25,120,170	$ 1,022,149	$ 2,328,640	$ 4,496,510	$ 1,833,772	$ 5,626,918	$ (1,479,841)	$ 15,307,989	$ 8,909,389	
8	$ 24,098,021	$ 1,022,149	$ 2,233,887	$ 4,313,546	$ 1,759,156	$ 5,397,957	$ (1,479,841)	$ 14,726,693	$ 8,010,345	
9	$ 23,075,872	$ 1,022,149	$ 2,139,133	$ 4,130,581	$ 1,684,539	$ 5,168,995	$ (1,479,841)	$ 14,145,397	$ 7,190,803	
10	$ 32,914,204	$ 1,384,165	$ 3,051,147	$ 5,891,642	$ 2,402,737	$ 7,372,782	$ (2,003,958)	$ 20,102,473	$ 9,550,540	
11	$ 31,530,039	$ 1,384,165	$ 2,922,835	$ 5,643,877	$ 2,301,693	$ 7,062,729	$ (2,003,958)	$ 19,315,298	$ 8,576,223	
12	$ 30,145,874	$ 1,384,165	$ 2,794,523	$ 5,396,111	$ 2,200,649	$ 6,752,676	$ (2,003,958)	$ 18,528,123	$ 7,688,512	
13	$ 28,761,709	$ 1,384,165	$ 2,666,210	$ 5,148,346	$ 2,099,605	$ 6,442,623	$ (2,003,958)	$ 17,740,949	$ 6,880,246	
14	$ 27,377,544	$ 1,384,165	$ 2,537,898	$ 4,900,580	$ 1,998,561	$ 6,132,570	$ (2,003,958)	$ 16,953,774	$ 6,144,828	
15	$ 38,166,439	$ 1,789,934	$ 3,538,029	$ 6,831,793	$ 2,786,150	$ 8,549,282	$ (2,591,419)	$ 23,495,187	$ 7,958,633	
16	$ 36,376,505	$ 1,789,934	$ 3,372,102	$ 6,511,394	$ 2,655,485	$ 8,148,337	$ (2,591,419)	$ 22,477,252	$ 7,115,722	
17	$ 34,586,572	$ 1,789,934	$ 3,206,175	$ 6,190,996	$ 2,524,820	$ 7,747,392	$ (2,591,419)	$ 21,459,317	$ 6,349,038	
18	$ 32,796,638	$ 1,789,934	$ 3,040,248	$ 5,870,598	$ 2,394,155	$ 7,346,447	$ (2,591,419)	$ 20,441,382	$ 5,652,212	
19	$ 31,006,704	$ 1,789,934	$ 2,874,321	$ 5,550,200	$ 2,263,489	$ 6,945,502	$ (2,591,419)	$ 19,423,446	$ 5,019,388	
20	$ 42,829,204	$ 2,243,681	$ 3,970,267	$ 7,666,428	$ 3,126,532	$ 9,593,742	$ (3,248,344)	$ 26,600,650	$ 6,424,405	
21	$ 40,585,523	$ 2,243,681	$ 3,762,278	$ 7,264,809	$ 2,962,743	$ 9,091,157	$ (3,248,344)	$ 25,324,668	$ 5,716,111	
22	$ 38,341,842	$ 2,243,681	$ 3,554,289	$ 6,863,190	$ 2,798,954	$ 8,588,573	$ (3,248,344)	$ 24,048,687	$ 5,072,996	
23	$ 36,098,160	$ 2,243,681	$ 3,346,299	$ 6,461,571	$ 2,635,166	$ 8,085,988	$ (3,248,344)	$ 22,772,705	$ 4,489,562	
24	$ 33,854,479	$ 2,243,681	$ 3,138,310	$ 6,059,952	$ 2,471,377	$ 7,583,403	$ (3,248,344)	$ 21,496,724	$ 3,960,754	
25	$ 46,800,356	$ 2,750,000	$ 4,338,393	$ 8,377,264	$ 3,416,426	$ 10,483,280	$ (3,981,378)	$ 29,365,362	$ 5,056,583	
26	$ 44,050,356	$ 2,750,000	$ 4,083,468	$ 7,885,014	$ 3,215,676	$ 9,867,280	$ (3,981,378)	$ 27,801,437	$ 4,474,096	
27	$ 41,300,356	$ 2,750,000	$ 3,828,543	$ 7,392,764	$ 3,014,926	$ 9,251,280	$ (3,981,378)	$ 26,237,512	$ 3,946,180	
28	$ 38,550,356	$ 2,750,000	$ 3,573,618	$ 6,900,514	$ 2,814,176	$ 8,635,280	$ (3,981,378)	$ 24,673,587	$ 3,468,189	
29	$ 35,800,356	$ 2,750,000	$ 3,318,693	$ 6,408,264	$ 2,613,426	$ 8,019,280	$ (3,981,378)	$ 23,109,662	$ 3,035,850	
TOTAL	$ 945,474,062	$ 49,449,644	$ 87,645,446	$ 169,239,857	$ 69,019,607	$ 211,786,190	$ (71,591,908)	$ 587,140,743	$ 210,354,201	

Table 7: WGD Project Cost

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 40,000,000	$ 1,333,333	$ 3,708,000	$ 7,160,000	$ 2,920,000	$ 8,960,000	$ 24,081,333	$ 22,505,919	$ 16,689,231
1	$ 38,666,667	$ 1,333,333	$ 3,584,400	$ 6,921,333	$ 2,822,667	$ 8,661,333	$ 23,323,067	$ 20,371,270	
2	$ 37,333,333	$ 1,333,333	$ 3,460,800	$ 6,682,667	$ 2,725,333	$ 8,362,667	$ 22,564,800	$ 18,419,598	
3	$ 36,000,000	$ 1,333,333	$ 3,337,200	$ 6,444,000	$ 2,628,000	$ 8,064,000	$ 21,806,533	$ 16,636,100	
4	$ 34,666,667	$ 1,333,333	$ 3,213,600	$ 6,205,333	$ 2,530,667	$ 7,765,333	$ 21,048,267	$ 15,007,123	
5	$ 33,333,333	$ 1,333,333	$ 3,090,000	$ 5,966,667	$ 2,433,333	$ 7,466,667	$ 20,290,000	$ 13,520,084	
6	$ 32,000,000	$ 1,333,333	$ 2,966,400	$ 5,728,000	$ 2,336,000	$ 7,168,000	$ 19,531,733	$ 12,163,382	
7	$ 30,666,667	$ 1,333,333	$ 2,842,800	$ 5,489,333	$ 2,238,667	$ 6,869,333	$ 18,773,467	$ 10,926,329	
8	$ 29,333,333	$ 1,333,333	$ 2,719,200	$ 5,250,667	$ 2,141,333	$ 6,570,667	$ 18,015,200	$ 9,799,075	
9	$ 28,000,000	$ 1,333,333	$ 2,595,600	$ 5,012,000	$ 2,044,000	$ 6,272,000	$ 17,256,933	$ 8,772,550	
10	$ 26,666,667	$ 1,333,333	$ 2,472,000	$ 4,773,333	$ 1,946,667	$ 5,973,333	$ 16,498,667	$ 7,838,398	
11	$ 25,333,333	$ 1,333,333	$ 2,348,400	$ 4,534,667	$ 1,849,333	$ 5,674,667	$ 15,740,400	$ 6,988,926	
12	$ 24,000,000	$ 1,333,333	$ 2,224,800	$ 4,296,000	$ 1,752,000	$ 5,376,000	$ 14,982,133	$ 6,217,053	
13	$ 22,666,667	$ 1,333,333	$ 2,101,200	$ 4,057,333	$ 1,654,667	$ 5,077,333	$ 14,223,867	$ 5,516,261	
14	$ 21,333,333	$ 1,333,333	$ 1,977,600	$ 3,818,667	$ 1,557,333	$ 4,778,667	$ 13,465,600	$ 4,880,553	
15	$ 20,000,000	$ 1,333,333	$ 1,854,000	$ 3,580,000	$ 1,460,000	$ 4,480,000	$ 12,707,333	$ 4,304,413	
16	$ 18,666,667	$ 1,333,333	$ 1,730,400	$ 3,341,333	$ 1,362,667	$ 4,181,333	$ 11,949,067	$ 3,782,768	
17	$ 17,333,333	$ 1,333,333	$ 1,606,800	$ 3,102,667	$ 1,265,333	$ 3,882,667	$ 11,190,800	$ 3,310,954	
18	$ 16,000,000	$ 1,333,333	$ 1,483,200	$ 2,864,000	$ 1,168,000	$ 3,584,000	$ 10,432,533	$ 2,884,682	
19	$ 14,666,667	$ 1,333,333	$ 1,359,600	$ 2,625,333	$ 1,070,667	$ 3,285,333	$ 9,674,267	$ 2,500,014	
20	$ 13,333,333	$ 1,333,333	$ 1,236,000	$ 2,386,667	$ 973,333	$ 2,986,667	$ 8,916,000	$ 2,153,331	
21	$ 12,000,000	$ 1,333,333	$ 1,112,400	$ 2,148,000	$ 876,000	$ 2,688,000	$ 8,157,733	$ 1,841,308	
22	$ 10,666,667	$ 1,333,333	$ 988,800	$ 1,909,333	$ 778,667	$ 2,389,333	$ 7,399,467	$ 1,560,894	
23	$ 9,333,333	$ 1,333,333	$ 865,200	$ 1,670,667	$ 681,333	$ 2,090,667	$ 6,641,200	$ 1,309,290	
24	$ 8,000,000	$ 1,333,333	$ 741,600	$ 1,432,000	$ 584,000	$ 1,792,000	$ 5,882,933	$ 1,083,926	
25	$ 6,666,667	$ 1,333,333	$ 618,000	$ 1,193,333	$ 486,667	$ 1,493,333	$ 5,124,667	$ 882,445	
26	$ 5,333,333	$ 1,333,333	$ 494,400	$ 954,667	$ 389,333	$ 1,194,667	$ 4,366,400	$ 702,686	
27	$ 4,000,000	$ 1,333,333	$ 370,800	$ 716,000	$ 292,000	$ 896,000	$ 3,608,133	$ 542,671	
28	$ 2,666,667	$ 1,333,333	$ 247,200	$ 477,333	$ 194,667	$ 597,333	$ 2,849,867	$ 400,585	
29	$ 1,333,333	$ 1,333,333	$ 123,600	$ 238,667	$ 97,333	$ 298,667	$ 2,091,600	$ 274,767	
TOTAL	$ 620,000,000	$ 40,000,000	$ 57,474,000	$ 110,980,000	$ 45,260,000	$ 138,880,000	$ 392,594,000	$ 207,097,355	

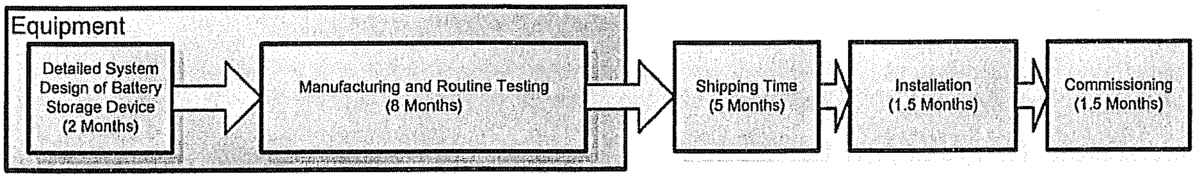
Table 8: Proposed Project Cost

Power Quality & Reliability Services	PV	
$ (1,013,442)	0.934579439	$ (947,141.85)
$ (1,013,442)	0.873438728	$ (885,179.30)
$ (1,013,442)	0.816297877	$ (827,270.37)
$ (1,013,442)	0.762895212	$ (773,149.88)
$ (1,013,442)	0.712986179	$ (722,569.98)
$ (1,479,841)	0.666342224	$ (986,080.27)
$ (1,479,841)	0.622749742	$ (921,570.35)
$ (1,479,841)	0.582009105	$ (861,280.70)
$ (1,479,841)	0.543933743	$ (804,935.23)
$ (1,479,841)	0.508349292	$ (752,275.92)
$ (2,003,958)	0.475092796	$ (952,066.00)
$ (2,003,958)	0.444011959	$ (889,781.31)
$ (2,003,958)	0.414964448	$ (831,571.32)
$ (2,003,958)	0.387817241	$ (777,169.45)
$ (2,003,958)	0.36244602	$ (726,326.59)
$ (2,591,419)	0.338734598	$ (877,803.37)
$ (2,591,419)	0.31657439	$ (820,376.98)
$ (2,591,419)	0.295863916	$ (766,707.46)
$ (2,591,419)	0.276508333	$ (716,549.02)
$ (2,591,419)	0.258419003	$ (669,671.99)
$ (3,248,344)	0.241513087	$ (784,517.47)
$ (3,248,344)	0.225713165	$ (733,193.90)
$ (3,248,344)	0.210946883	$ (685,227.94)
$ (3,248,344)	0.19714662	$ (640,399.95)
$ (3,248,344)	0.184249178	$ (598,504.62)
$ (3,981,378)	0.172195493	$ (685,575.42)
$ (3,981,378)	0.160930367	$ (640,724.69)
$ (3,981,378)	0.150402212	$ (598,808.12)
$ (3,981,378)	0.140562815	$ (559,633.76)
$ (3,981,378)	0.131367117	$ (523,022.21)
	TOTAL	$ (22,959,085)

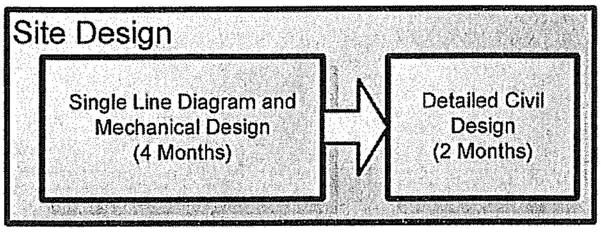
Table 9: Power Quality & Reliability Service Benefit

Construction schedule and expected online date:

The chart below outlines the estimated schedule of 18 months



During the 10 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Technical Data

The following pieces of technical information are attached to this application:

- Network model for power flow study in GE-PSLF format
    - stockton.epc
- GE PSLF Batt model and model parameters
    - PSLF_batt_Model.pdf
    - BATT_epcl_parameters.xls
- Sample one line diagram
    - NAS Battery System SLD.pdf

Miscellaneous Data

Proposed entity to construct, own, and finance the project

Western Grid Development, LLC (WGD) will own the storage device project and will act as project manager during construction. WGD will also be responsible for financing the project.

Planned operator of the project

WGD will file to become a PTO under the CAISO tariff and will operate the project upon completion.

REQUEST WINDOW SUBMISSION FORM

Please fill in and submit a **signed copy** of this completed form along with the attachment A (technical data) to the CAISO contact listed in section 3. Please note that this form should be used for the purpose of submitting information that applies to the scope of Request Window of CAISO Transmission Planning Process only. For more information on the Request Window Submission, please refer to the Business Practice Manual for the Transmission Planning Process which is available at http://caiso.com/2024/20246de967b0.pdf

1. The undersigned CAISO Stakeholder Customer submits this request to be considered in the CAISO Transmission Plan. This submission is for (check one)[1]:

- ☒ Reliability Transmission Project (refer to section 1 of attachment A)
- ☐ Merchant Transmission Facility (refer to section 1 of attachment A)
- ☐ Economic Transmission Project (refer to section 1 of attachment A)
- ☐ Location Constrained Resource Interconnection Facility (LCRIF) (refer to sections 1 & 2 of attachment A)
- ☐ Project to preserve Long-term Congestion Revenue Rights (CRR) (refer to section 1 of attachment A)
- ☐ Economic Planning Study Request (refer to section 3 of attachment A)
- ☐ Others (refer to section 4 of attachment A)

2. For the submission of a Reliability, Merchant, Economic, LCRIF, and CRR project, the project sponsor is

- ☒ Seeking ISO approval in this planning cycle
- ☐ Submitting for information only (not requiring ISO approval in this planning cycle)

3. Please provide the following basic information about this submission:

a. Address or location of the proposal. Please provide the information that best describes the overall physical locations or route of the project:

Project Name: **Tulucay 60kV Energy Storage Project**

Submission Date: **November 30, 2009**

b. Project locations or the proposed interconnection point(s) :

PG&E's Tulucay 60kV Substation

c. Project capacity (Net MW):

25MW

d. Descriptions of the project. Please provide the overview and the overall scope of the proposed project e.g. overall scope, objectives etc.

The 2010 CAISO Local Capacity Technical Analysis (May 1, 2009) for the North Coast/North Bay area identified that the Vaca Dixon - Tulucay 230kV line will reach 100.0% of its emergency rating for the loss of Vaca Dixon – Lakeville 230kV line with

[1] Please contact the ISO staff at requestwindow@caiso.com for any questions regarding the definitions of these submission categories in this form to the ISO

Delta Energy Center offline. The CAISO defines a LCR requirement of 787 MW to reliably serve the load in the Lakeville Sub Area.

North Coast/North Bay Overall Requirements:

2010	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	18	131	736	885

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	787	0	787
Category C (Multiple)[12]	787	3	790

Table 1: North Coast/ North Bay Overall Requirements

WGD is proposing an alternative solution to the 787MW of resources that are needed in 2010, which includes installing a 25MW battery storage device at the Tulucay 60kV substation in 2011. The proposed solution could be used to fulfill the capacity requirement post 2010 as load increases and no major upgrades are planned in the area. In fact a closer look at the changes from 2009 to 2010 LCR requirement reveals the following:

The 2010 LCR need for the Pittsburg/Oakland sub-area (part of the Greater Bay Area) has decreased by 400MW, as a result the Lakeville LCR need has increased by 87MW. The overall load forecast went up by 18MW which drives the LCR requirement up by 24MW.

This project will reduce the overall LCR requirement for the North Coast/North Bay area by 42MW.

e. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by month, day, and year and term of service.

Proposed In-Service date:	**12 / 30 / 2010**
Proposed Trial Operation date:	**12 / 30 / 2010**
Proposed Commercial Operation date:	**12 / 30 / 2010**
Proposed Term of Service:	**30 Years**

f. Name, address, telephone number, and e-mail address of the Project Sponsor.

Name: **John Dizard**

Title:	**Managing Member**
Company Name:	**Western Grid Development, LLC**
Street Address:	**200 East 94th Street, Suite 2218**
City, State:	**New York, NY**

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
CAISO TRANSMISSION PLANNING PROCESS
REQUEST WINDOW SUBMISSION FORM

Zip Code:	10128
Phone Number:	[illegible]
Fax Number:	212-937-4622
Email Address:	dizard@gmail.com

c) Technical Data (set forth in Attachment A):

☒ Is attached to this Request
☐ Will be provided at a later date

4. This Request Window submission request shall be submitted to the following CAISO representative:

Dana Young
Regional Transmission
California ISO
151 Blue Ravine Road, Folsom, CA 95630

5. This Request is submitted by: Western Grid Development, LLC

Name of the Customer:	Western Grid Development, LLC
By (signature):	
Name (type or print):	John Dizard
Title:	Managing Member
Company Name:	Western Grid Development, LLC
Street Address:	[illegible]
City, State:	New York, NY
Zip Code:	10128
Phone Number:	[illegible]
Email Address:	dizard@gmail.com
Date:	November 30, 2009

CAISO TRANSMISSION PLANNING PROCESS

Attachment A: Required Technical data for Request Window Submission

Please provide all information that applies to each type of submission. For any questions regarding these technical data, please contact CAISO for more information.

1. Transmission Projects

This section applies to all transmission project submissions. It does not apply to Economic Planning Study Requests.

Any transmission project, including those seeking cost recovery through Long-term Congestion Revenue Rights, whether submitted by a PTO, non-PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to[2]:

General Data

- Description of the proposal such as the scope, interconnection points, proposed route, the nature of alternative (AC/DC) or expected benefits
- A diagram shows Geographical location and proposed preferred project route

Technical Data

- Network model for power flow study in GE-PSLF format. In some cases, Dynamic models for stability study in GE-PSLF format may also be required

Planning Level Cost Data[3]

- Project construction costs estimate, schedule, anticipated operations, and other data necessary for the study.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

[2] This appendix lists the minimum amount of data required by the ISO for the first screening purposes. Additional data may be requested by the ISO later during the course of project evaluation

[3] Not required for Merchant Transmission Facilities

2. Location Constrained Resource Interconnection Facilities (LCRIFs)

Any party proposing a Location Constrained Resource Interconnection Facility shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

A description of the proposed facility, setting forth:

- Transmission study results demonstrating that the transmission facility meets applicable reliability requirements and CAISO Planning Standards
- Identification of the most .feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
- A planning level cost estimate for the proposed facility and all proposed alternatives
- An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
- The estimated in-service date of the proposed facility, and
- A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF:

- The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area.
- The transmission facility will be a High Voltage Transmission Facility.
- At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF.

3. Economic Planning Studies

Requests to perform an Economic Planning Study must identify:

- Requester Name, Address, and other contact information
- The congested transmission element (binding constraint) or limiting facilities to be studied or other information supporting the potential for increased future Congestion on the binding constraint.

As identified in the scope of the Economic Planning Study, requester may submit up to 2 conceptual mitigation plans along with each study request. However, for each conceptual mitigation plan to be considered, sufficient data i.e. network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives, must be provided to CAISO by the closing date of Request Window.

4. Submission under "Other" category

This category of submission includes other type of proposals that may be considered as alternatives in the transmission planning process such as generation, demand response programs, new technologies etc. However, the ISO encourages project sponsors to contact CAISO staff prior to submitting these proposals through the Request Window.

General Data

Description of Project

Please see the attached report which includes a full reliability analysis and economic analysis on all WGD proposed projects.

The 2010 CAISO Local Capacity Technical Analysis (May 1, 2009) for the North Coast/North Bay area identified that the Vaca Dixon - Tulucay 230kV line will reach 100.0% of its emergency rating for the loss of Vaca Dixon – Lakeville 230kV line with Delta Energy Center offline. The CAISO defines a LCR requirement of 787 MW to reliably serve the load in the Lakeville Sub Area.

North Coast/North Bay Overall Requirements:

2010	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	18	131	736	885

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	787	0	787
Category C (Multiple)[12]	787	3	790

Table 2: North Coast/ North Bay Overall Requirements

WGD is proposing an alternative solution to the 787MW of resources that are needed in 2010, which includes installing a 25MW battery storage device at the Tulucay 60kV substation in 2011. The proposed solution could be used to fulfill the capacity requirement post 2010 as load increases and no major upgrades are planned in the area. In fact a closer look at the changes from 2009 to 2010 LCR requirement reveals the following:

The 2010 LCR need for the Pittsburg/Oakland sub-area (part of the Greater Bay Area) has decreased by 400MW, as a result the Lakeville LCR need has increased by 87MW. The overall load forecast went up by 18MW which drives the LCR requirement up by 24MW.

This project will reduce the overall LCR requirement for the North Coast/North Bay area by 42MW.

Required Storage Device Size

The CAISO load flow study was reproduced using the 2010 CAISO LCR case. The base case was tuned to show the element at its emergency rating with the loss of Vaca Dixon – Lakeville 230kV line and DEC offline. The tuned results can be seen in Figure 1 below.

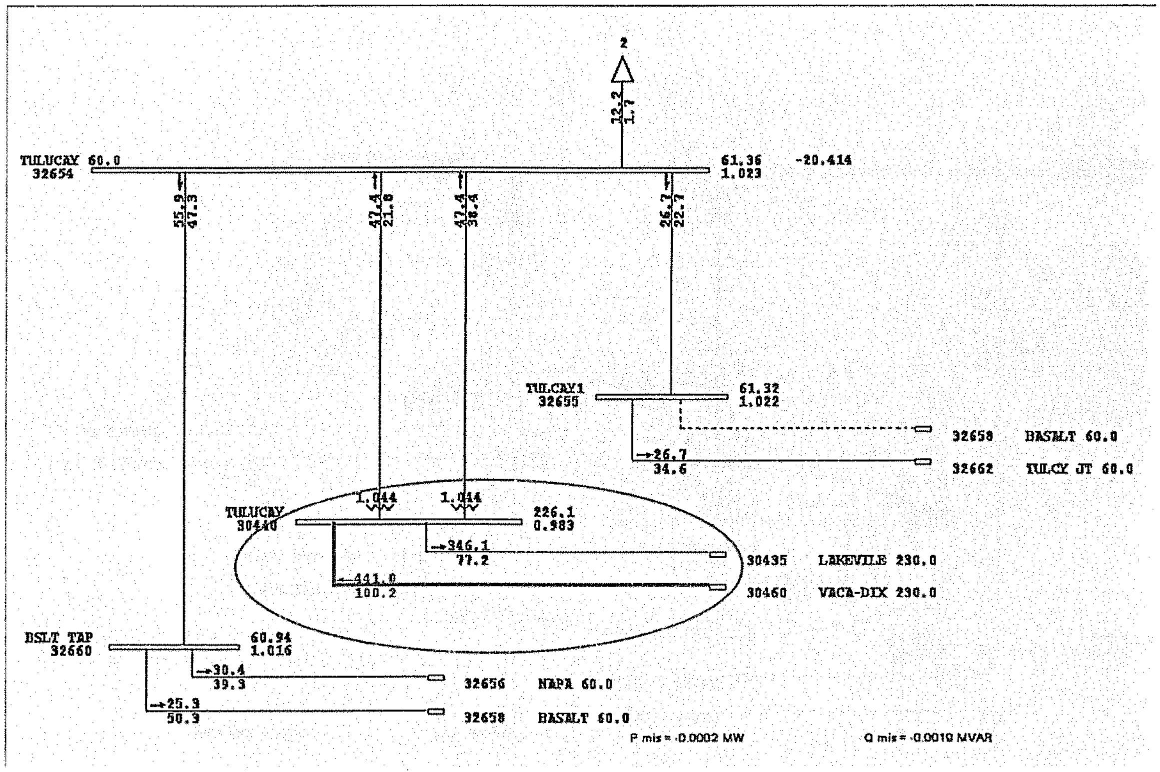


Figure 1: Tuned Storage Device Results

It was determined that approximately 25MW of battery storage would be required to displace 42MW of LCR requirement. This was done by taking the LCR study case showing the max line flow with Vaca Dixon – Lakeville 230kV and DEC out of service. An energy storage device was then added to the Tulucay 60 kV bus and Geysers #20 was taken offline. Geysers #20 is a unit that is needed for the North Coast/North Bay LCR area (Lakeville sub-area).

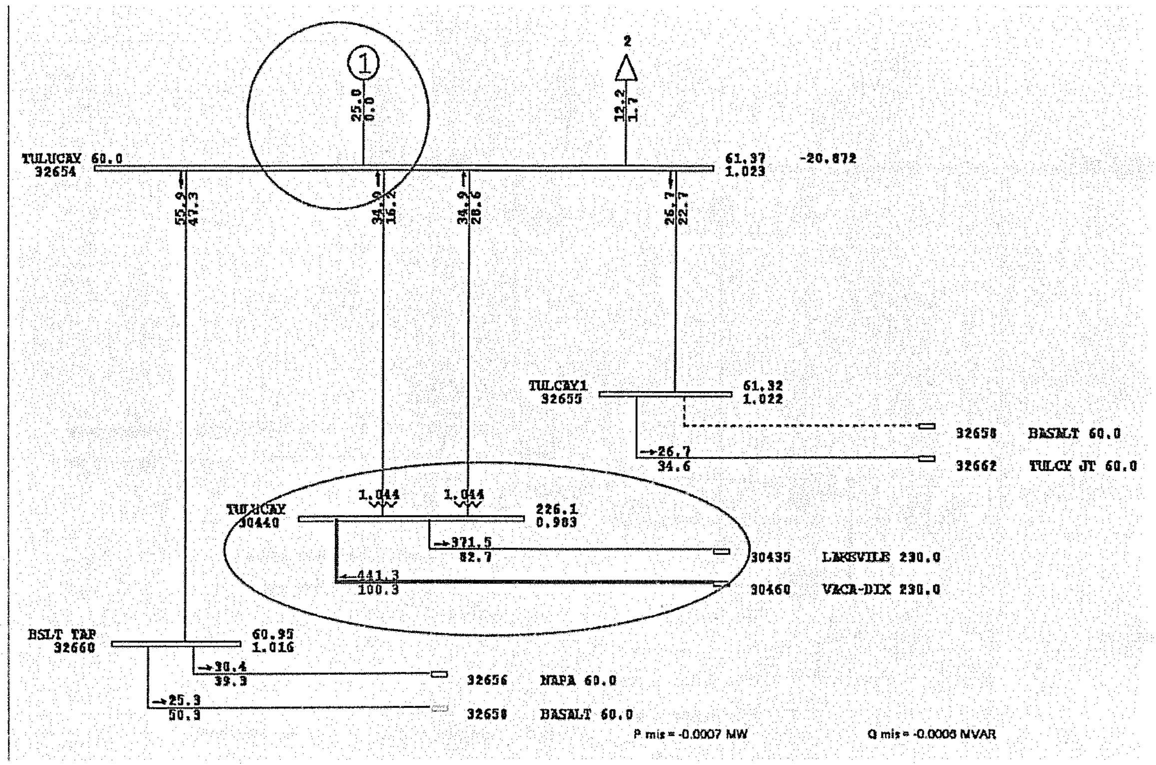


Figure 2: Storage Device Results

Economic Analysis

Based on information and belief PG&E calculates depreciation in the following manner:

$$\frac{[CapitalCost - SalvageValue]}{DepreciationPeriod}$$

WGD proposes using a service life of 30 years. Table 3 below shows the WGD ratemaking assumptions.

Assumption	Value	Pre-Calculations
n = Asset Life (Years)	30	-
Salvage Value ($)	$3,750,000.0	10%
Capital Cost ($)	$37,500,000.0	25MW*$1.5M
$Depreciation = \frac{Capital\ Cost - Salvage\ Value}{Asset\ Life}$	-	$1,125,000.00
O&M = Operations and Maintanance	17.9%	-
A&G = Administrative and General	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 3: WGD Ratemaking Assumptions

Assumption	Value	Pre-Calculations
(Years)	30	-
Salvage Value	$0.0	-
Capital Cost ($)	$40,000,000.0	-
[illegible]	-	$1,333,333.33
O&M =	17.9%	-
A&G =	7.30%	-
Cost of Capital	9.27%	-
Taxes	22.4%	-
i = Interest Rate	7.00%	-

Table 4: Alternative Project Ratemaking Assumptions

Using the assumptions listed above, our analysis indicates that the WGD solution has a levelized annual revenue requirement of $16.2M compared to $16.7M for the alternative reconductor project. The overall project cost was calculated at $201.2M NPV compared to $207.0M NPV for the alternative reconductor project with an additional $22.5M in Power Quality and Reliability Services. The alternative reconductor project to WGD cost ratio is 1.14% indicating a large economic benefit as the WGD project is 14% less expensive than the alternative reconductor project solution.

Year (n)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Power Quality & Reliability Services	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 37,600,000	$ 1,125,000	$ 3,476,250	$ 6,712,500	$ 2,737,600	$ 8,400,000	$ (1,809,717)	$ 22,461,250	$ 20,982,477	$ 16,211,164
1	$ 36,375,000	$ 1,125,000	$ 3,371,963	$ 6,511,125	$ 2,655,375	$ 8,148,000	$ (1,809,717)	$ 21,811,463	$ 19,050,976	
2	$ 35,250,000	$ 1,125,000	$ 3,267,675	$ 6,309,750	$ 2,573,250	$ 7,896,000	$ (1,809,717)	$ 21,171,675	$ 17,282,393	
3	$ 34,125,000	$ 1,125,000	$ 3,163,388	$ 6,108,375	$ 2,491,125	$ 7,644,000	$ (1,809,717)	$ 20,531,888	$ 15,663,679	
4	$ 33,000,000	$ 1,125,000	$ 3,059,100	$ 5,907,000	$ 2,409,000	$ 7,392,000	$ (1,809,717)	$ 19,892,100	$ 14,182,792	
5	$ 31,875,000	$ 1,125,000	$ 2,954,813	$ 5,705,625	$ 2,326,875	$ 7,140,000	$ (1,809,717)	$ 19,252,313	$ 12,828,629	
6	$ 30,750,000	$ 1,125,000	$ 2,850,525	$ 5,504,250	$ 2,244,750	$ 6,888,000	$ (1,809,717)	$ 18,612,525	$ 11,590,945	
7	$ 29,625,000	$ 1,125,000	$ 2,746,238	$ 5,302,875	$ 2,162,625	$ 6,636,000	$ (1,809,717)	$ 17,972,738	$ 10,460,297	
8	$ 28,500,000	$ 1,125,000	$ 2,641,950	$ 5,101,500	$ 2,080,500	$ 6,384,000	$ (1,809,717)	$ 17,332,950	$ 9,427,976	
9	$ 27,375,000	$ 1,125,000	$ 2,537,663	$ 4,900,125	$ 1,998,375	$ 6,132,000	$ (1,809,717)	$ 16,693,163	$ 8,486,957	
10	$ 26,250,000	$ 1,125,000	$ 2,433,375	$ 4,698,750	$ 1,916,250	$ 5,880,000	$ (1,809,717)	$ 16,053,375	$ 7,626,843	
11	$ 25,125,000	$ 1,125,000	$ 2,329,088	$ 4,497,375	$ 1,834,125	$ 5,628,000	$ (1,809,717)	$ 15,413,588	$ 6,843,817	
12	$ 24,000,000	$ 1,125,000	$ 2,224,800	$ 4,296,000	$ 1,752,000	$ 5,376,000	$ (1,809,717)	$ 14,773,800	$ 6,130,602	
13	$ 22,875,000	$ 1,125,000	$ 2,120,513	$ 4,094,625	$ 1,669,875	$ 5,124,000	$ (1,809,717)	$ 14,134,013	$ 5,481,414	
14	$ 21,750,000	$ 1,125,000	$ 2,016,225	$ 3,893,250	$ 1,587,750	$ 4,872,000	$ (1,809,717)	$ 13,494,225	$ 4,890,928	
15	$ 20,625,000	$ 1,125,000	$ 1,911,938	$ 3,691,875	$ 1,505,625	$ 4,620,000	$ (1,809,717)	$ 12,854,438	$ 4,354,243	
16	$ 19,500,000	$ 1,125,000	$ 1,807,650	$ 3,490,500	$ 1,423,500	$ 4,368,000	$ (1,809,717)	$ 12,214,650	$ 3,866,845	
17	$ 18,375,000	$ 1,125,000	$ 1,703,363	$ 3,289,125	$ 1,341,375	$ 4,116,000	$ (1,809,717)	$ 11,574,863	$ 3,424,564	
18	$ 17,250,000	$ 1,125,000	$ 1,599,075	$ 3,087,750	$ 1,259,250	$ 3,864,000	$ (1,809,717)	$ 10,935,075	$ 3,023,639	
19	$ 16,125,000	$ 1,125,000	$ 1,494,788	$ 2,886,375	$ 1,177,125	$ 3,612,000	$ (1,809,717)	$ 10,295,288	$ 2,660,498	
20	$ 15,000,000	$ 1,125,000	$ 1,390,500	$ 2,685,000	$ 1,095,000	$ 3,360,000	$ (1,809,717)	$ 9,655,500	$ 2,331,930	
21	$ 13,875,000	$ 1,125,000	$ 1,286,213	$ 2,483,625	$ 1,012,875	$ 3,108,000	$ (1,809,717)	$ 9,015,713	$ 2,034,555	
22	$ 12,750,000	$ 1,125,000	$ 1,181,925	$ 2,282,250	$ 930,750	$ 2,856,000	$ (1,809,717)	$ 8,375,925	$ 1,766,675	
23	$ 11,625,000	$ 1,125,000	$ 1,077,638	$ 2,080,875	$ 848,625	$ 2,604,000	$ (1,809,717)	$ 7,736,138	$ 1,525,153	
24	$ 10,500,000	$ 1,125,000	$ 973,350	$ 1,879,500	$ 766,500	$ 2,352,000	$ (1,809,717)	$ 7,096,350	$ 1,307,497	
25	$ 9,375,000	$ 1,125,000	$ 869,063	$ 1,678,125	$ 684,375	$ 2,100,000	$ (1,809,717)	$ 6,456,563	$ 1,111,391	
26	$ 8,250,000	$ 1,125,000	$ 764,775	$ 1,476,750	$ 602,250	$ 1,848,000	$ (1,809,717)	$ 5,816,775	$ 936,096	
27	$ 7,125,000	$ 1,125,000	$ 660,488	$ 1,275,375	$ 520,125	$ 1,596,000	$ (1,809,717)	$ 5,176,988	$ 778,630	
28	$ 6,000,000	$ 1,125,000	$ 556,200	$ 1,074,000	$ 438,000	$ 1,344,000	$ (1,809,717)	$ 4,537,200	$ 637,762	
29	$ 4,875,000	$ 1,125,000	$ 451,913	$ 872,625	$ 355,875	$ 1,092,000	$ (1,809,717)	$ 3,897,413	$ 511,992	
TOTAL	$ 635,625,000	$ 32,750,000	$ 58,922,433	$ 113,776,875	$ 46,400,625	$ 142,380,000	$ (54,291,524)	$ 395,229,938	$ 201,282,225	

Table 5: WGD Cost Alternatives

Year (*n*)	Initial Cost and Installation	Depreciation	Return	O&M	A&G	Taxes	Rate based Revenue Requirement	Present Value (PV)	Levilized Revenue Requirement
0	$ 40,000,000	$ 1,333,333	$ 3,708,000	$ 7,160,000	$ 2,920,000	$ 8,960,000	$ 24,081,333	$ 22,505,919	$ 16,689,231
1	$ 38,666,667	$ 1,333,333	$ 3,584,400	$ 6,921,333	$ 2,822,667	$ 8,661,333	$ 23,323,067	$ 20,371,270	
2	$ 37,333,333	$ 1,333,333	$ 3,460,800	$ 6,682,667	$ 2,725,333	$ 8,362,667	$ 22,564,800	$ 18,419,598	
3	$ 36,000,000	$ 1,333,333	$ 3,337,200	$ 6,444,000	$ 2,628,000	$ 8,064,000	$ 21,806,533	$ 16,636,100	
4	$ 34,666,667	$ 1,333,333	$ 3,213,600	$ 6,205,333	$ 2,530,667	$ 7,765,333	$ 21,048,267	$ 15,007,123	
5	$ 33,333,333	$ 1,333,333	$ 3,090,000	$ 5,966,667	$ 2,433,333	$ 7,466,667	$ 20,290,000	$ 13,520,084	
6	$ 32,000,000	$ 1,333,333	$ 2,966,400	$ 5,728,000	$ 2,336,000	$ 7,168,000	$ 19,531,733	$ 12,163,382	
7	$ 30,666,667	$ 1,333,333	$ 2,842,800	$ 5,489,333	$ 2,238,667	$ 6,869,333	$ 18,773,467	$ 10,926,329	
8	$ 29,333,333	$ 1,333,333	$ 2,719,200	$ 5,250,667	$ 2,141,333	$ 6,570,667	$ 18,015,200	$ 9,799,075	
9	$ 28,000,000	$ 1,333,333	$ 2,595,600	$ 5,012,000	$ 2,044,000	$ 6,272,000	$ 17,256,933	$ 8,772,550	
10	$ 26,666,667	$ 1,333,333	$ 2,472,000	$ 4,773,333	$ 1,946,667	$ 5,973,333	$ 16,498,667	$ 7,838,398	
11	$ 25,333,333	$ 1,333,333	$ 2,348,400	$ 4,534,667	$ 1,849,333	$ 5,674,667	$ 15,740,400	$ 6,988,926	
12	$ 24,000,000	$ 1,333,333	$ 2,224,800	$ 4,296,000	$ 1,752,000	$ 5,376,000	$ 14,982,133	$ 6,217,053	
13	$ 22,666,667	$ 1,333,333	$ 2,101,200	$ 4,057,333	$ 1,654,667	$ 5,077,333	$ 14,223,867	$ 5,516,261	
14	$ 21,333,333	$ 1,333,333	$ 1,977,600	$ 3,818,667	$ 1,557,333	$ 4,778,667	$ 13,465,600	$ 4,880,553	
15	$ 20,000,000	$ 1,333,333	$ 1,854,000	$ 3,580,000	$ 1,460,000	$ 4,480,000	$ 12,707,333	$ 4,304,413	
16	$ 18,666,667	$ 1,333,333	$ 1,730,400	$ 3,341,333	$ 1,362,667	$ 4,181,333	$ 11,949,067	$ 3,782,768	
17	$ 17,333,333	$ 1,333,333	$ 1,606,800	$ 3,102,667	$ 1,265,333	$ 3,882,667	$ 11,190,800	$ 3,310,954	
18	$ 16,000,000	$ 1,333,333	$ 1,483,200	$ 2,864,000	$ 1,168,000	$ 3,584,000	$ 10,432,533	$ 2,884,682	
19	$ 14,666,667	$ 1,333,333	$ 1,359,600	$ 2,625,333	$ 1,070,667	$ 3,285,333	$ 9,674,267	$ 2,500,014	
20	$ 13,333,333	$ 1,333,333	$ 1,236,000	$ 2,386,667	$ 973,333	$ 2,986,667	$ 8,916,000	$ 2,153,331	
21	$ 12,000,000	$ 1,333,333	$ 1,112,400	$ 2,148,000	$ 876,000	$ 2,688,000	$ 8,157,733	$ 1,841,308	
22	$ 10,666,667	$ 1,333,333	$ 988,800	$ 1,909,333	$ 778,667	$ 2,389,333	$ 7,399,467	$ 1,560,894	
23	$ 9,333,333	$ 1,333,333	$ 865,200	$ 1,670,667	$ 681,333	$ 2,090,667	$ 6,641,200	$ 1,309,290	
24	$ 8,000,000	$ 1,333,333	$ 741,600	$ 1,432,000	$ 584,000	$ 1,792,000	$ 5,882,933	$ 1,083,926	
25	$ 6,666,667	$ 1,333,333	$ 618,000	$ 1,193,333	$ 486,667	$ 1,493,333	$ 5,124,667	$ 882,445	
26	$ 5,333,333	$ 1,333,333	$ 494,400	$ 954,667	$ 389,333	$ 1,194,667	$ 4,366,400	$ 702,686	
27	$ 4,000,000	$ 1,333,333	$ 370,800	$ 716,000	$ 292,000	$ 896,000	$ 3,608,133	$ 542,671	
28	$ 2,666,667	$ 1,333,333	$ 247,200	$ 477,333	$ 194,667	$ 597,333	$ 2,849,867	$ 400,585	
29	$ 1,333,333	$ 1,333,333	$ 123,600	$ 238,667	$ 97,333	$ 298,667	$ 2,091,600	$ 274,767	
TOTAL	$ 620,000,000	$ 40,000,000	$ 57,474,000	$ 110,980,000	$ 45,260,000	$ 138,880,000	$ 392,594,000	$ 207,097,355	

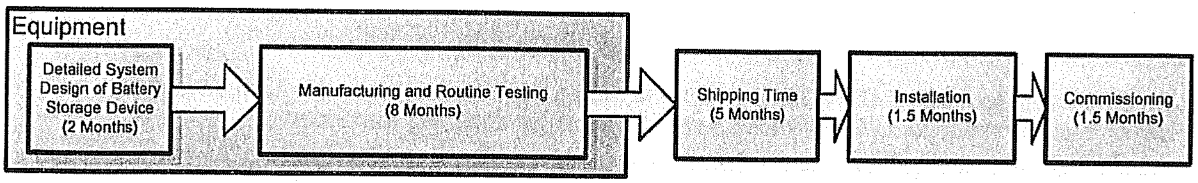
Table 6: Alternative Project Cost Estimate

Power Quality & Reliability Services	PV	
$ (1,809,717)	0.934579439	$ (1,691,325)
$ (1,809,717)	0.873438728	$ (1,580,677)
$ (1,809,717)	0.816297877	$ (1,477,269)
$ (1,809,717)	0.762895212	$ (1,380,625)
$ (1,809,717)	0.712986179	$ (1,290,304)
$ (1,809,717)	0.666342224	$ (1,205,891)
$ (1,809,717)	0.622749742	$ (1,127,001)
$ (1,809,717)	0.582009105	$ (1,053,272)
$ (1,809,717)	0.543933743	$ (984,366)
$ (1,809,717)	0.508349292	$ (919,969)
$ (1,809,717)	0.475092796	$ (859,784)
$ (1,809,717)	0.444011959	$ (803,536)
$ (1,809,717)	0.414964448	$ (750,968)
$ (1,809,717)	0.387817241	$ (701,840)
$ (1,809,717)	0.36244602	$ (655,925)
$ (1,809,717)	0.338734598	$ (613,014)
$ (1,809,717)	0.31657439	$ (572,910)
$ (1,809,717)	0.295863916	$ (535,430)
$ (1,809,717)	0.276508333	$ (500,402)
$ (1,809,717)	0.258419003	$ (467,665)
$ (1,809,717)	0.241513087	$ (437,070)
$ (1,809,717)	0.225713165	$ (408,477)
$ (1,809,717)	0.210946883	$ (381,754)
$ (1,809,717)	0.19714662	$ (356,780)
$ (1,809,717)	0.184249178	$ (333,439)
$ (1,809,717)	0.172195493	$ (311,625)
$ (1,809,717)	0.160930367	$ (291,238)
$ (1,809,717)	0.150402212	$ (272,186)
$ (1,809,717)	0.140562815	$ (254,379)
$ (1,809,717)	0.131367117	$ (237,737)
	Total	$ (22,456,859)

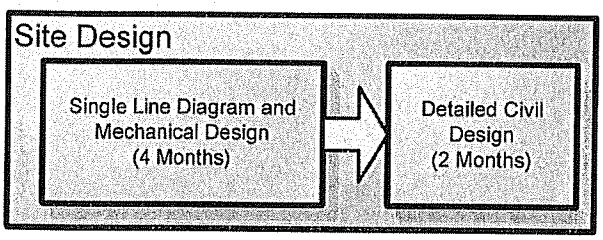
Table 7: Power Quality and Reliability Services Estimates

Construction schedule and expected online date:

The chart below outlines the estimated schedule of 18 months



During the 10 month equipment process outlined above a 6 month site design process will need to simultaneously be performed.



Technical Data

The following pieces of technical information are attached to this application:

- Network model for power flow study in GE-PSLF format
  - tulucay.epc
- GE PSLF Batt model and model parameters
  - PSLF_batt_Model.pdf
  - BATT_epcl_parameters.xls
- Sample one line diagram
  - NAS Battery System SLD.pdf

Miscellaneous Data

Proposed entity to construct, own, and finance the project

Western Grid Development, LLC (WGD) will own the storage device project and will act as project manager during construction. WGD will also be responsible for financing the project.

Planned operator of the project

WGD will file to become a PTO under the CAISO tariff and will operate the project upon completion.

ATTACHMENT U

California ISO
Your Link to Power

Final California ISO Transmission Plan

2010

April 7, 2010

Prepared by

Market & Infrastructure Development
California Independent System Operator Corporation

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3.3.2.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

Thermal Overload Mitigations

Lakeville 230/60 kV Bank #3
The proposed solution to mitigate this category C overload is to disable the automatic switching scheme during summer peak conditions and include this scheme in the operating procedure. This operating procedure may result in load dropping in the area which is radially fed from Lakeville 230 kV substation. The study results show that this mitigation plan is needed in 2010 and it could require lead time of several months to develop the operating procedure.

Hopland 115/60 kV Bank #2
The proposed solution to mitigate this category C overload is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions, The study results show that this mitigation plan is in 2010 and it could require lead time of several months to develop the operating procedure,

Vaca Dixon - Lakeville Ckt #1 and Tulucay - Vaca Dixon Ckt #1 230 kV Lines

The ISO reliability study results showed that mitigation plans are needed for potential overloads on 1) Vaca Dixon – Lakeville and 2) Vaca Dixon - Tulucay 230 kV Lines. In addition, the ISO LCR study results also show that the Vaca Dixon - Tulucay 230 kV line is the limiting facility that drives LCR requirements in the North Coast/North Bay area.

Western Grid Development, LLC (WGD) proposed a battery storage reliability-driven project, the Tulucay 60 kV Energy Storage Project, to address reliaibility concerns in the area. The Tulucay 60 kV Energy Storage Project would be installed at the Tulucay 60 kV bus. The capital cost of WGD's project is $37.5 million. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control and to recover the cost of the facilities through the ISO's TAC. However, ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO Board has previously approved a project to reconductor the Vaca Dixon-Tulucay and Vaca Dixon-Lakeville 230 kV lines. Once completed, that project will address all of the reliability needs in the area. However, the ISO failed to model this project in its studies. In the interim, load serving entities have been procuring sufficient local generation to ensure that overloads will not occur. Also, there is an operating procedure to open these two lines under contingency conditions and relieve the overload on either line.

Thus, WGD has proposed a project that addresses a reliability need for which the ISO already has a Board-approved project. Moreover, the WGD project only solves one of the two identified reliability needs in the area. The project approved by the ISO Board resolves both. Specifically, although WGD's studies show that the battery storage project will reduce power flows from Vaca Dixon to Tulucay substations, the ISO study results show that the project will not mitigate potential overload on the parallel Vaca Dixon – Lakeville 230 kV line.

Furthermore, the reconductoring project will significantly reduce LCR requirements in the North Coast / North Bay area by reinforcing two key import lines to the area. This is in contrast with WGD's project that will not significantly reduce LCR since it relieves overload only on one bottleneck. Thus, the ISO is rejecting WGD's Tulucay 60 kV battery storage project.

Bridgeville - Garberville 60 kV Line #1
The proposed solution to mitigate this category C overload is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions. The study results show that this mitigation plan is needed in 2010 and it could require lead time of several months to develop the operating procedure

Mendocino - Redbud 115 kV #1 and Eagle Rock - Redbud 115 kV #1
The proposed solution to mitigate this category C overload is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions. The study results show that this mitigation plan is needed prior to 2010 and it could require lead time of several months to develop the operating procedure,

Geysers 3 - Cloverdale 115 kV Line #1
The proposed solution to mitigate this category C overload is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions. The study results show that this mitigation plan is needed prior to 2010 and it could require lead time of several months to develop the operating procedure

Fulton - Santa Rosa 115 kV Line #1 and Fulton - Santa Rosa 115 kV Line #2
The proposed solution to mitigate these category C overloads is to develop or modify an existing operating procedure to drop the load supplied from these lines under contingency conditions. The study results show that this mitigation plan is needed prior to 2012 and it could require lead time of several months to develop the operating procedure.

Santa Rosa - Coronoa 115 kV Line #1, Coronoa - Lakeville 115 kV Line #1, Sonoma - Pueblo 115 kV Line #1,and Fulton - Calistoga 60 kV Line #1
The proposed solution to mitigate these category C overloads is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions. The study results show that this mitigation plan is needed prior to 2010 and it could require lead time of several months to develop the operating procedure.

Lakeville #2 60kV Line #1
The proposed solution to mitigate this category C overload is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions. The study results show that this mitigation plan is needed prior to 2010 and it could require lead time of several months to develop the operating procedure.

Fulton - Pueblo 115 kV Line #1
The proposed solution to mitigate this category C overload is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions. The study results show that this mitigation plan is needed prior to 2013 and it could require lead time of several months to develop the operating procedure.

Mendocino - Clear Lake 60 kV Line #1
The proposed solution to mitigate this category C overload is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions. The study results show that this mitigation plan is needed after 2017 and it could require lead time of several months to develop the operating procedure.

Mendocino - Willits - Fort Bragg 60 kV Line #1
The proposed solution to mitigate this category C overload is to develop or modify an existing operating procedure to drop the load in the north Geysers area under contingency conditions. The study results

3.3.4.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

Atlantic-Placer Voltage Conversion-Category A, B and C
Under normal conditions, the Placer 115/60 kV transformer could overload starting in year 2017. Also, under normal conditions, low voltages could appear in the area starting in year 2018. There are two potential overloads for category B single outage conditions starting in 2016. There are also multiple existing potential overloads, as well as low voltage and voltage deviations for category C conditions that can be mitigated by upgrading the Atlantic-Rocklin-Del Mar-Penryn-Placer system to 115 kV operation. This would be achieved by upgrading the existing Atlantic-Del Mar #1 and #2 60 kV to 115 kV operations, as well as rebuilding Placer-Del Mar to a 115 kV DCTL and having the entire system looped through. The most feasible implementation timeline for this upgrade is 2016 due to permitting and lead times. In the interim, load shedding will be used for most category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Auburn 60 kV Energy Storage
Western Grid Development, LLC proposed a battery storage reliability-driven project, the Auburn 60 kV Energy Storage Project, to address some of the reliability concerns in the Placer area. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control. However, ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

Thus, the ISO will evaluate the battery storage project to determine whether PG&E should be directed to install such facility to address reliability needs in the area. The Placer area is very complex with both peak and off-peak transmission constraints driven by load, hydro and import patterns. Due to these factors, the operation of this system is extremely dynamic, with multiple constraints that need to be mitigated throughout the day. The ISO considers all the possible reliability problems in the area as being interrelated and any solution or solutions adopted to address these needs must complement each other and assure full compliance with reliability standards. In other words, this area requires a comprehensive long-term solution to address all the concerns. The ISO will consider the Atlantic - Placer voltage upgrade and the Auburn battery storage project, along with other possible options in the next ISO planning cycle to determine what facilities PG&E should be required to construct to meet the reliability needs in this area.

Madison-Vaca Dixon 115 kV Reconductoring-Category A
Under normal conditions, this line could overload by year 2014. Rerate is the preferred alternative. If rerate fails reconductoring this radial line could be a solution. The most feasible implementation timeline for this upgrade is 2014 due to permitting and lead times.

Madison-Vaca Dixon 115 kV Line Rerate
In response to this proposal the ISO has received the Madison-Vaca Dixon 115 kV line rerate project from PG&E with operating date May 1, 2014. The ISO recommends that PG&E pursue this alternative as soon as possible. Equipment rerates do not need ISO approval. The cost of the rerate is rather minimal usually less than $100,000 and the expected rating is about 12-15% higher. This line loading is increasing at a rate of about 1% per year; as such a successful rerate would mitigate then need for about 12-15 years, moving the need for a transmission project to 2026-2029 timeframe.

Madison 115 kV Energy Storage
Western Grid Development, LLC proposed a battery storage reliability-driven project, the Madison 115 kV Energy Storage Project, to address the same reliability concerns addressed by the PG&E proposal to

rerate the Vaca-Madison 115 kV line. WGD's proposed project has an initial capital cost of $4.5 million. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO staff considered the proposed battery storage project as an alternative to the rerating of the Vaca-Madison 115 kV line to determine whether PG&E should be directed to install battery storage facilities. It was determined that there is no need for the battery storage project, or any other transmission upgrade or addition, because the Vaca-Madison 115 kV line can be rerated at minimal cost, significantly below the cost of installing a battery storage unit. It is expected that the rerate will increase the rating of the line by 12-15% and defer the need for any new transmission upgrade in this area. Once the line is rerated, there will not be any overload concerns. The Madison Storage project addresses the same reliability needs as the preferred alternative but at significantly higher cost. Hence, the Madison 115 kV Energy Storage Project is rejected.

Tesla-Weber 230 kV Reconductoring-Category A, B and C

Under normal conditions this line could overload by year 2016. There are also two potential overloads for category B single outage conditions and one for category C multiple contingency conditions starting in 2015. Reconductoring this network line could be a solution. The most feasible implementation timeline for this upgrade is 2015 due to permitting and lead times. This plan will be assessed further and included in the next annual ISO transmission plan.

Mosher Area Reinforcement-Category A, B, C and D

Under normal conditions the Hummer-Country Club and Stagg-Hummer 60 kV lines could overload starting in year 2015. Also for the loss of the Country Club-Hummer 60 kV, the Mosher substation transfers to the Lockeford #1 60 kV line potentially overloading it. The Mosher substation has over 50 MW of load and, as such, it should have a looped service. There are numerous category B and C contingencies with very high potential overloads as well as low voltages and voltage drops in both the Stagg 60 kV as well as Lockeford 60 kV when Mosher is served from either side. There are also some category C and D contingencies with divergence. Solution includes upgrading this substation to 115 kV or 230 kV service. Since the Mosher substation is in proximity of the Industrial substation a common project to upgrade both to preferably a new 230 kV service on a double circuit tower line coming from the general Eight Mile area would benefit both and possibly Hummer substation as well. Also it would constitute the third leg (out of four) into achieving a 230 kV ring around the Stockton area. The most feasible implementation timeline for this project is 2015 due to permitting and lead times. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Industrial Area Reinforcement-Category A, B and C

Under normal conditions the voltage at the Lockeford 230 kV bus can reach 0.94 pu by year 2019. There are a few single and numerous overlapping contingencies with low voltages, as well as voltage deviations in the area. There are also numerous Category C conditions with high potential overloads in this area. Designing an SPS that follows the ISO guidelines for this magnitude of different components is more challenging if at all possible and it does not constitute a long-term solution for the area. Further aggravating the situation is that the contingencies with higher voltage drop diverge if the Lodi CT is not on-line suggesting a potential voltage collapse in this area. The biggest substation in this area is Industrial with about 150 MW of load. Solution includes upgrading this substation to 115 kV or 230 kV service. Since the industrial substation is in proximity of the Mosher substation a common project to upgrade both to preferably a new 230 kV service on a double circuit tower line coming from the general Eight Mile area would benefit both and possibly Hummer substation as well. Also it would constitute the third leg (out of four) into achieving a 230 kV ring around the Stockton area. The most feasible implementation timeline for this project is 2015 due to permitting and lead times. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Tesla-Bellota 115 kV Area Reinforcement-Category A, B and C
Under normal conditions the Tesla-Kasson-Manteca 115 kV line could overload starting in year 2015. There are numerous single and overlapping contingencies with potential overloads in this area. This area has an existing LCR requirement as well. One of the solutions includes looping the Tesla-Stockton-Co-gen Junction 115 kV into the Vierra, Manteca, Kasson or Tracy substations and additional reconductoring if necessary. Another solution would be to upgrade part of the 60 kV Lee tap to 115 kV operations in order to close a 115 kV loop between the Ripon Co-gen and Ripon substation with additional reconductoring if necessary. Also another solution would be to move some of the substations with higher load like Tracy or Manteca to 230 kV service. The most feasible implementation timeline for this project is 2015 due to permitting and lead times. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Stockton "A"-Weber #1 60 kV Line Reconductoring-Category A, B and C
Under normal conditions the Stockton A-Weber #160 kV line could overload starting in year 2018. Also, currently there are two single and one overlapping contingencies with potential overload on the same line. Solution includes reconductoring 4.5 miles of the Stockton "A"-Weber #1 60 kV line from Weber to Santa Fee Switches. The most feasible implementation timeline for this upgrade due to permitting and lead time is 2011. In the interim load shedding will be used for both category B and C conditions.

Stockton "A"-Weber #2 60 kV Line Reconductoring-Category B and C
There is one single contingency starting in 2020 and one existing overlapping contingency with potential overload on this 60 kV line. Solution includes reconductoring 4.5 miles of the Stockton "A"-Weber #2 60 kV line from Weber to Santa Fee Switches. Most feasible project implementation, due to permitting and lead times is 2011. In the interim load shedding will be used for both category B and C conditions.

Stockton "A"-Weber #1 & #2 60 kV Line Reconductor
In response to the last two proposals the ISO has received the Stockton "A"-Weber #1 & #2 60 kV line reconductor project from PG&E with operating date May 1, 2011 at a cost of $5-10 Million. The ISO approves this project.
It has demonstrated that the preferred alternative is a prudent and technically sound solution to the identified reliability concerns. The reconductoring of portions of these two lines plus the rerate of the Stockton "A"-Weber #3 60 kV line is the most cost effective mitigation to the possible reliability concerns in the area.

Stockton 60 kV Energy Storage
Western Grid Development, LLC proposed a battery storage reliability-driven project, the Stockton 60 kV Energy Storage Project, to address the same reliability concerns as the Stockton "A"-Weber #1 and #2 60 kV reconductoring project. The battery storage unit would have an initial capital cost of $21 milllion, with the cost to increase as more MW are added. Western Grid Development, LLC proposed to build and own the battery storage projects, to turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO staff considered the proposed battery storage project as an alternative to the reconductoring project to determine whether PG&E should be directed to install battery storage facilities. Although it was determined that the Stockton Energy storage project addresses the same reliability needs as the preferred alternative - reconductoring portions of the line, it does so at much higher cost. The reconductor project has a capital cost of $5-10 million. Therefore, the Stockton 60 kV Energy Storage Project is rejected.

Rio Oso/Gold Hill Area Voltage Support-Category A
Under normal conditions numerous 230 kV buses in the area could have below 0.95 pu voltage starting in year 2017. Solution includes installation of voltage support in the area. There is more than ample time for

permitting, procurement and installation before 2017. This plan will be assessed further and included in the next annual ISO transmission plan.

Plainfield Area Reconductoring or Voltage Support-Category A

Under normal conditions the Plainfield 60 kV bus could have below 0.95 pu voltage starting in year 2014. Solution includes installation of voltage support or reconductoring of about 7 miles of the Vaca-Plainfield Jct. 60 kV line. The most feasible implementation timeline for this upgrade is 2014 due to permitting and lead times. This plan will be assessed further and included in the next annual ISO transmission plan.

Westley Area Reconductoring or Voltage Support-Category A

Under normal conditions the Westley 60 kV bus could have below 0.95 pu voltage starting in year 2012. Solution includes installation of voltage support or reconductoring of about 12 miles of the Manteca #1 60 kV line. The most feasible implementation timeline for this project is 2012 due to permitting and lead times. This plan will be assessed further and included in the next annual ISO transmission plan.

Woodland-Davis-West Sacramento Long-Term-Category A, B, C and D

Under normal conditions the voltage at the Brighton 230 kV bus can reach 0.94 pu by year 2014. There are numerous category B and C contingencies with very high potential overloads as well as low voltages and voltage drops in both this area. There are also some category C and D contingencies with divergence. Designing an SPS that follows the ISO guidelines for this magnitude of different components is more that challenging if at all possible and it does not constitute a long-term solution for the area. Woodland Biomass, the only generator in this area, has been dispatched at maximum during these studies. As such, the ISO would have to use pre-contingency load shedding immediately after the first contingency in order to protect the equipment for the loss of the next contingency per WECC and NERC standards; inconsequential loss of load after a single contingency is very likely in this area. Further aggravating the situation is the fact that many contingencies in 2019 timeframe diverge due to high overloads and no voltage support, thus suggesting a potential voltage collapse in this area. The biggest substations in this area are Woodland, Davis and West Sacramento. Solution includes upgrading some of these substations to 230 kV service. For instance a new Vaca Dixon-Davis-Woodland 230 kV 23 miles DCTL can be build. Another solution would be to upgrade Vaca-Dixon #1 and #2 from 60 to 115 kV and additional 115 kV miscellaneous reconductoring. A third option would be to reconductor most every line in this 115 kV system. Final design could include a combination of the above alternatives that meet ISO and WECC/NERC standards. The most feasible implementation timeline for this project is 2017 due to permitting and lead times. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

West Sacramento Transmission Project

In response to part of this proposal the ISO has received the West Sacramento Transmission Project from PG&E with operating date December 1, 2010. The ISO approved this project.

It has demonstrated that the preferred alternative is a prudent and technically sound solution to the identified reliability concerns. This Special Protection Scheme only addresses a small portion of the reliability needs in the area however the ISO believes that this project will be needed even with implementation of the long-term solution for the entire area: West Sacramento-Davis long-term plan.

Rio Oso-Atlantic 230 kV Reconductoring-Category B and C

Under one category B, starting in 2020, and two category C contingency conditions the Rio Oso-Atlantic 230 kV line could overload and under one category C contingency condition the Rio Oso-Gold Hill 230 kV line could overload. There are also other overloads, low voltage and voltage deviation problems in the area for a few category C contingencies. This area has an existing LCR requirement as well. Solution includes looping the Rio Oso-Gold Hill 230 kV line into the Atlantic substation as well as reconductoring both Rio Oso-Atlantic 230 kV lines. Most feasible project implementation due to permitting and lead times is 2014. In the interim load shedding will be used for the category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Palermo-Pease-Rio Oso 115 kV Lines Reconductoring-Category B, and C

There is one single, starting in 2017, and numerous multiple contingencies in this area that could overload these lines. Solutions include reconductoring 50 miles of 115 kV lines and/or different arrangement of the 115 kV system in this area. Most feasible project implementation due to permitting and lead times is 2015. In the interim load shedding will be used for the category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Drum-Grass Valley-Weimar 60 kV Line-Category B and C
There are one existing category B and one C contingencies starting in 2011 with potential overloads as well as low voltages in this area. Solutions include reconductoring 20 miles of this 60 kV line. Another solution would be to disable the automatics at Grass Valley and to change the configuration at Weimar such that Forest Hill is served from Middle Fork. Most feasible project implementation due to permitting and lead times is 2015. In the interim load shedding will be used for category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Vaca-Suisun-Jameson 115 kV Reconductoring-Category B
The Vaca-Suisun-Jameson 115 kV line could overload for the loss of Vaca-Suisun 115 kV line with City Fair generator out of service starting in 2017. If these two contingencies happen one after the other the Vaca Dixon-Suisun-Jameson 115 kV will overload. Currently there is also one category C contingency that overloads this line and SPS is used to trip load as mitigation. Solution includes reconductoring about 18 miles of this line. There is more than ample time for permitting, procurement and installation before 2017. This plan will be assessed further and included in the next annual ISO transmission plan.

Vaca Dixon #5 115/60 kV Transformer Replacement-Category B
Currently the Vaca Dixon #5 115/60 kV transformer could overload for the loss of the Vaca Dixon #9 115/60 kV transformer. There is also one category C contingency that could overload this transformer. Solution includes replacing the Vaca Dixon #5 115/60 kV transformer or upgrading Dixon to 115 or 230 kV operation. Most feasible project implementation due to permitting and lead times is 2015. In the interim load shedding will be used for this category B condition. This plan will be assessed further and included in the next annual ISO transmission plan.

New Cortina 230/115/60 kV Transformer #2-Category B
Under two existing single contingency conditions the Cortina 230/115/60 kV transformer could overload. Solution includes the installation of a second Cortina 230/115/60 transformer (or a new 230/60 or 115/60 kV transformer) and a small SPS to cover new category C conditions or a new 230/60 kV transformer at Colusa with 60 kV rearrangement. Most feasible project implementation due to permitting and lead times is 2015. In the interim load shedding will be used for these category B conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Cortina #2 and #3 Reconductoring-Category B and C
There are a few existing single and overlapping contingencies with potential overloads as well as low voltages and voltage deviations in the area. Solution includes reconductoring these lines or changing/disabling automatics in the area. Most feasible project implementation due to permitting and lead times is 2015. In the interim load shedding will be used for these category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Stagg 230 kV Area Reinforcement-Category B and C
There are a few single, starting in year 2015, and numerous overlapping contingencies with potential overloads as well low voltages and voltage deviations in this area. The area has an existing LCR requirement as well. Solution includes reconductoring a total of 22 miles of the Tesla-Stagg 230 kV line and the Tesla-Stagg portion of the Tesla-Eight Mile 230 kV line then loops the Tesla-Eight Mile 230 kV line into Stagg and upgrade Stagg 230 kV bus to BAAH. If needed the project can be augmented with a UVLS and/or voltage support such the all category B and C concerns are mitigated. Most feasible project implementation due to permitting and lead times is 2015. In the interim load shedding will be used for these category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Linden Area Reinforcement-Category B and C
There are a few single contingencies starting in year 2012, and a few overlapping contingencies with potential overloads as well low voltages and voltage deviations in this area. The loss of Weber-Mormon Junction 60 kV line transfers Linden to the Valley Springs #1 60 kV line which could overload. Also this transfer could overload the Valley Springs 230/60 kV transformer. One solution includes disabling the automatics at Linden combined with the Weber-Mormon 60 kV reconductoring. Another solution would maintain the automatics and would reconductor the Valley Springs #1 60 kV along with the addition of a new 230/60 kV transformer at Valley Springs. A more elegant solution would be to upgrade Linden to 115 kV operations tapped on any one of the lines nearby like: Stockton "A"-Lockeford-Bellota #1, #2 or Gold Hill-Bellota-Lockeford 115 kV. Also a direct 5 mile 115 kV line could be constructed from Bellota to Linden. For these last few alternatives the Weber-Mormon 60 kV does not need to be reconductored. Most feasible project implementation due to permitting and lead times is 2015. In the interim load shedding will be used for these category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Weber #2 230/60 kV Transformer Replacement-Category B and C
Currently for the loss of the Weber #1 230/60 kV transformer the Weber #2&2A 230/60 kV transformer could overload. Under category C the above mentioned overload is aggravated by any generator loss in this area. All generators in this area have been dispatched as such the ISO would have to use pre-contingency load shedding immediately after the loss of any generator located here in order to protect the equipment for the loss of the next contingency per WECC and NERC standards in consequence loss of load after a single contingency is very likely in this area. Solution includes replacing the Weber #2 & 2A 230/60 kV transformer with a new 200 MVA 230/60 kV transformer. Most feasible implementation due to permitting and lead times is 2013. In the interim load shedding will be used for these category B and C conditions.

Weber 60 kV Bus Tie Replacement-Category B and C
Currently for the loss of the Weber #2 230/60 kV transformer the Weber 60 kV bus tie overloads. Under category C the above mentioned overload is aggravated by any generator loss in this area. All generators in this area have been dispatch as such the ISO would have to use pre-contingency load shedding immediately after the loss of any generator located here in order to protect the equipment for the loss of the next contingency per WECC and NERC standards in consequence loss of load after a single contingency is very likely in this area. Solution includes replacing the Weber 60 kV bus tie. Most feasible implementation due to permitting and lead times is 2013. In the interim load shedding will be used for these category B and C conditions.

Weber 230/60 kV Transformer #2&2A Replacement
In response to the above two proposals the ISO has received the Weber 230/60 kV transformer #2&2A replacement project proposed by PG&E with operating date May 1, 2013 at a cost of $8-15 million. The ISO approves this project.

It has demonstrated that the preferred alternative is a prudent and technically sound solution to the identified reliability concerns. The transformer replacement should be placed in service in an expedited manner.

Clarksville Area Reinforcement-Category B and C
There is one existing category C contingency in the area that could overload Gold Hill-Missouri Flat #1 115 kV line. There is one single and one multiple contingencies with low voltages in the area starting in 2018. Also the Clarksville substation has close to 200 MW of load, as such should be looped in. Solutions include reconductoring with 477 SSAC and upgrading to 115 kV operations the Gold Hill #1 60 kV line. Another solution would be to upgrade the Clarksville substation to 230 kV operations by looping the Gold Hill-Middle Fork 230 kV line into this substation. Most feasible project implementation, due to permitting and lead times is 2015. In the interim load shedding will be used for these category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Loop Tesla-Kasson-Manteca 115 kV into Lammers and/or Voltage Support-Category B and C

There are two single, starting in 2016, and one overlapping contingencies with potential low voltages and voltage deviations in this area. One of the solutions includes looping the Tesla-Kasson-Manteca 115 kV line into Lammers and/or voltage support. There is more than ample time for permitting, procurement and installation before 2016. This plan will be assessed further and included in the next annual ISO transmission plan.

Kasson-Manteca 60 kV System Rearrangement-Category B and C
There are a few existing overlapping and possible common mode DCTL contingencies with potential overloads in this area. Also there are one category B and one category C contingencies with low voltages and high voltage deviations in the area starting in 2013. One of the solutions includes de-looping the Kasson-Manteca 60 kV system under normal conditions. Another solution would be to implement a SPS or an operating procedure in order to achieve de-looping. Most feasible project implementation, due to permitting and lead times is 2011. In the interim load shedding will be used for these category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Upgrade Gold Hill 115 kV Bus to BAAH-Category C
Currently the loss of the Gold Hill 115 kV Bus Section #2 has significantly low voltages and very high voltage deviations in the area. For year 2019 this contingency diverges. Solutions include upgrading the Gold Hill 115 kV bus to BAAH. Most feasible project implementation, due to permitting and lead times is 2014. In the interim load shedding will be used for this category C condition. This plan will be assessed further and included in the next annual ISO transmission plan.

Gold Hill #3 230/115 kV Transformer-Category C
Under multiple contingency the Gold Hill #1 and/or #2 230/115 kV transformer could overload and for the loss of both the case diverges staring in 2010. Solutions include the addition of a third 230/115 kV 420 MVA bank at Gold Hill plus an SPS for the new category C contingency. This solution depends on the options chosen for the Clarksville area reinforcement as well as the upgrade of the Atlantic-Placer system from 60 to 115 kV operations. Most feasible project implementation, due to permitting and lead times is 2015. In the interim load shedding will be used for these category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Bogue-Rio Oso 115 kV line Reconductoring-Category C
Currently for the simultaneous DCTL loss of the Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV the Bogue-Rio Oso 115 kV line could overload. Solutions include reconductoring of the remaining portions of this line. Most feasible project implementation, due to permitting and lead times is 2013. In the interim load shedding will be used for these category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Drum-Rio Oso #1 and #2 115 kV Operating Procedures and/or Reconductoring-Category C
Currently under multiple contingency these lines could overload. Solutions include generation curtailment through operating procedures and or line reconductoring. Most feasible project implementation, due to permitting and lead times is 2010. This plan will be assessed further and included in the next annual ISO transmission plan.

New Rio Oso-Pleasant Grove 115 kV Line-Category C
For the simultaneous DCTL loss of the Rio Oso-Gold Hill and Rio Oso-Atlantic the Rio Oso-Lincoln-Pleasant Grove 115 kV lines could overload starting in 2011. Also for the loss of the Rio Oso-Lincoln 115 kV followed by Atlantic Pleasant Grove #1 or #2 the remaining one could overload starting in 2011. There are no resources in this area that could be dispatched to mitigate this problem as such load needs to be dropped pre-contingency (within 30 minutes after the loss of the first element) unless a new SPS is installed to prevent the expected overload after the second contingency. Solutions include a new Rio Oso-Pleasant Grove 115 kV line. Another solution would be the installation of two new SPS for the two particular problems anticipated above. This last solution however will constrain the south of Rio Oso flow much more then the first option. Most feasible project implementation, due to permitting and lead times, is 2013. In the interim load shedding will be used for these category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Sierra Peaker Project
StarTrans proposed this generation resource project to address reliability concerns and achieve LCR deficiency reduction. In its request window submission, StarTrans submitted the project as a reliability transmission project and sought recovery of the costs of the project in the ISO's transmsison access charge (TAC). StarTrans did not submit the project as an "Other" project which includes projects that are intended as alternatives to transmission, including generation and demand response. The cost of non-transmisison alternatives are recovered through applicable market mechanisms, not the TAC, because they are not transmission assets. The ISO's TAC provides for rate recovery only for transmission assets, not generation assets. Because the peaker is a generation resource, not a transmission resource, it is not eligible for recovery in TAC. Accordingly, this project is rejected. This project can be submitted in the generation interconnection process if StarTrans desires to pursue the project as a generaion resource. The new Rio Oso-Pleasant Grove 115 kV line along with other alternatives to this plan will be assessed further and included in the next annual ISO transmission plan.

Cortina Voltage Support-Category C
Starting in 2011, under category C contingency conditions, for the loss of one 230 kV source in the Cortina substation followed by the loss of the second 230 kV source, the Cortina 115 and 60 kV system voltages are very depressed with high voltage deviations. In 2019 this contingency diverges. One solution includes looping another one of the three remaining 230 kV lines that run north to south from Cottonwood to Vaca into the Cortina substation. A second solution would be to add voltage support at the Cortina substation. A third solution would be to install an SPS to trip load and/or de-loop the 230 kV bus such that the entire Cortina 115 kV and 60 kV load is dropped for this contingency. Most feasible project implementation, due to permitting and lead times is 2013. In the interim load shedding will be used for these category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Vaca Dixon #2&2A 230/115 kV Transformer Replacement -Category C
Currently under multiple contingency the Vaca Dixon #2&2A transformer could significantly overload. Solutions include the replacement of this bank addition of an addition forth 230/115 kV 420 MVA bank at Vaca Dixon or an SPS. Most feasible project implementation, due to permitting and lead times is 2015. In the interim load shedding will be used for these category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

New Vaca Dixon 230/115 kV Transformer, SPS or new 230/115 kV Station-Category C
Under multiple contingency the Vaca Dixon #2&2A, #3 and #4 transformers could overload starting in year 2019. Solutions include the addition of a new 230/115 kV transformer (forth) or the opening of a new 230/115 kV station in the vicinity or an SPS. There is more than ample time for permitting, procurement and installation before 2019. This plan will be assessed further and included in the next annual ISO transmission plan.

Electra-Bellota 230 kV Operating Procedure-Category C
Under multiple contingency this line could overload starting in year 2019. Solutions include new operating procedure for generation curtailment. There is more than ample time for developing this operating procedure before 2019. This plan will be assessed further and included in the next annual ISO transmission plan.

Hammer Area Reliability-Category C
Even when the Mosher area reinforcement is implemented there will still be some category C overlapping contingencies with potential overloads in this area. The loss of any two of Stagg-Hammer and Stagg-Country Club #1 and #2 60 kV lines would overload the remaining one. There are no generators in this area so the ISO would have to use pre-contingency load shedding immediately after the first contingency in order to protect the equipment for the loss of the next contingency per WECC and NERC standards. Consequently, loss of load after a single contingency is very likely in this area. One solution includes upgrading this loop to 115 kV operations. Another will rebuild the Stagg-Hammer 60 kV to a DCTL. A third solution will build a new 230 kV substation north of Hammer 60 kV from the new 230 kV DCTL that

serves Mosher and Industrial and will move enough load of the Hammer substation such that overloads are not expected. A last alternative would add two SPS in the area; one at Hammer and one at Country Club in order to drop enough load such that and overload is not encountered for any category C contingency. Most feasible project implementation, due to permitting and lead times is 2015. In the interim load shedding will be used for most category B and C conditions in the area. This plan will be assessed further and included in the next annual ISO transmission plan.

New Tesla 230/115 kV Transformer-Category C
Currently for the loss of Tesla #1 and #3 230/115 kV transformers there are high overloads on the LLNL 230/115 kV transformer and low voltages in the area. Solutions include the addition of a new 230/115 kV transformer (third) or moving some of the 115 kV load to the 230 kV system through the Tesla-Bellota 115 kV area reinforcement project and/or a new SPS. Most feasible project implementation, due to permitting and lead times is 2015. In the interim load shedding will be used for this category C condition. This plan will be assessed further and included in the next annual ISO transmission plan.

New Bellota 230/115 kV Transformer-Category C
Starting in 2011 for the loss of Bellota #1 and #2 230/115 kV transformers there are overloads on the Bellota-River Bank-Mellones SW STA 115 kV line and very low voltages and high voltage deviations in the area. Solutions include the addition of a new 230/115 kV transformer (third) or moving some of the 115 kV load to the 230 kV system through the Tesla-Bellota 115 kV area reinforcement project and/or a new SPS. Most feasible project implementation, due to permitting and lead times is 2015. In the interim load shedding will be used for this category C condition. This plan will be assessed further and included in the next annual ISO transmission plan.

Stockton "A" Reinforcement-Category C
Currently for the loss of the Stockton "A"-Lockeford-Bellota #1 115 kV line and the Gold Hill-Bellota-Lockeford 115 kV line the Stockton "A"-Lockeford-Bellota #2 115 kV line could overload. The Stockton "A" 115 kV substation has over 90 MW of load and should be looped in not drop and pick-up. Solution includes the reconductoring of 24 miles for both 115 kV lines from Stockton Junction to Stockton "A" and loops the system through. Most feasible project implementation, due to permitting and lead times is 2015. In the interim load shedding will be used for this category C condition. This plan will be assessed further and included in the next annual ISO transmission plan.

Stockton "A"-Weber #3 60 kV Line Reconductoring-Category C
There is one overlapping contingency with potential overload on this 60 kV line, starting in 2011. Solution includes reconductoring 4.5 miles of the Stockton "A"-Weber #3 60 kV line from Weber to Santa Fee Switches or a new SPS needs to be installed. Most feasible project implementation, due to permitting and lead times is 2011. In the interim load shedding will be used for this category C condition.

Stockton "A"-Weber #3 60 kV Line Rerate
In response to this proposal the ISO has received the Stockton "A"-Weber #3 60 kV line rerate project from PG&E with operating date May 1, 2011. The ISO recommends that PG&E pursue this alternative as soon as possible. Equipment rerates do not need ISO approval. The cost of the rerate is rather minimal usually less than $100,000 and the expected rating is about 12-15% higher. This line loading is increasing at a rate of about 1.2% per year; as such a successful rerate would mitigate then need for about 10-13 years, moving the need for a transmission project to 2021-2024 timeframe.

Encinal UVLS-Category C
Under category C conditions the loss of the Pease 60 kV bus; the voltages around Encinal could be below 0.92 pu starting in 2019. Solution includes installing a UVLS at Encinal in order to trip load when the voltage is below 0.92 pu; another solution is to upgrade Pease 60 kV bus to BAAH. There is more than ample time for developing this operating procedure before 2019. This plan will be assessed further and included in the next annual ISO transmission plan.

Curtis UVLS-Category C

Starting in 2010 under category C conditions the loss of the Bellota-Riverbank-Mellones and Donnells-Curtis 115 kV lines; the voltages around Curtis are very low and have high voltage deviations. Solution includes installing a UVLS at Curtis in order to trip load when the voltage is below 105 kV. Most feasible project implementation, due to permitting and lead times is 2011. In the interim load shedding will be used for this category C condition. This plan will be assessed further and included in the next annual ISO transmission plan.

3.3.4.5 Key Conclusions

Based on the ISO assessment Central Valley area had:

- Seven overloads and 14 low voltages under normal conditions;
- 29 overloads caused by 36 critical contingencies; 10 worst buses with low voltages caused by 12 critical contingencies, as well as eight worst voltage deviations caused by eight critical contingencies under single contingency conditions;
- 64 overloads caused by 71 critical contingency conditions, 28 worst buses with low voltages caused by 29 critical contingencies as well as 20 worst voltage deviations caused by 21 critical contingencies and eight contingencies with divergent cases under multiple contingency conditions; and
- 12 divergent cases (potential voltage collapse) among the extreme contingency studied.

In order to address the identified overloads, the ISO proposed 42 transmission solutions while the request window produced 12 project proposals:

- Three projects were approved;
- Three projects were rejected;
- Six projects are being evaluated by the ISO and they will move forward into the 2010 planning cycle for further analysis;
- ISO will coordinate with PG&E regarding an additional 32 transmission solutions proposed by ISO.

Three approved projects will carry forward into the 2010 planning cycle and included in the planning assumptions. The remaining ISO proposals will be carried forward into the 2011 Transmission Plan.

3.3.5.5 Key Conclusions

Based on the ISO study assessment, the Greater Bay Area had:

- One thermal overload under a normal condition by 2016;
- Five overloads caused by five critical single contingencies under summer peak conditions; and
- 76 overloads caused by 65 critical multiple contingencies under summer peak conditions.

Among the scenarios studied, none produced extreme contingency conditions with potential voltage collapse.

In order to address the identified overloads, the ISO proposed a total of 37 transmission solutions and the request window produced 12 reliability project proposals. Out of these proposals:

- Four projects were approved;
- Four projects will be carried forward into the 2010 planning cycle for further analysis;
- Four projects were rejected;
- ISO will coordinate with PG&E regarding an additional 11[7] transmission solutions proposed by ISO.

The four approved projects will carry forward into the 2010 PC and included in the planning assumptions. The remaining ISO proposals will be carried forward into the 2011 TP (*i.e.*, 2010 PC).

The four rejected projects include one generation project, two transmission projects and one battery storage project.

StarTrans proposed the Standard Oil Peaker project. This generation project competes directly with the SanPablo/Point Pinole 115 kV voltage project. In its request window submission, StarTrans submitted the project as a reliability transmission project and sought recovery of the cost of the project in the ISO's transmsison access charge (TAC). StarTrans' did not submit the project as an "Other" project which includes projects that are intended as alternatives to transmission, including generation and demand response. The costs of non-transmisison alternatives are recovered through applicable market mechanisms, not the TAC, because they are not transmission assets. The ISO's TAC provides for rate recovery only for transmission assets, not generation assets. Because the peaker is a generation resource, not a transmission resource, it is not eligible for recovery in TAC. Accordingly, this project is rejected. This project can be submitted in the generation interconnection process if StarTrans desires to pursue the project as a generation asset.

One of the transmission projects rejected is the San Francisco 115 kV Series Reactor Project which according to PG&E is needed in 2019-2020 time frames. ISO considers this a conceptual project too far into the future, and will be reconsidered in the coming years along with alternatives such as re-cabling of the 60 year old Martin - Hunters Point cables. The second transmission project rejected is a new Embarcadero-Potrero 230 kV cable, which have been determined through City of San Francisco system reliability analysis (section 7.3) as not needed for the next 10 year planning horizon.

Western Grid Development, LLC proposed a battery storage reliability-driven project, the Potrero 115 kV Energy Storage Project, to address apparent capacity need in San Francisco in 2011. WGD's project would have an initial capital cost of $30 million. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control and to recover the costs of the facilities through the ISO's TAC. However, ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

[7] Some proposed projects will address multiple overload issues.

As a result of the recabling of the Martin-Bayshore-Portrero lines which signifianctly increased the ratings of these lines, there are no identified overloads. Accordingly, there is no reliability need for WGD's battery storage project or some other transmission project in the area. Hence, the ISO is rejecting the Potrero Energy Storage Project.

3.3.6.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

Thermal Overload Mitigations

Gates-500 kV Ckt #1 Line
The line between Gates 500 kV To Midway 500 kV Ckt #1 was identified as overloaded under NERC Category A conditions in the 2014 off peak case to 100%. The mitigation plan is to curtail Path 15 flow in 2014.

McMulln1-Kearney 230 kV Ckt #1 Line
The line section between McMulln1 230 kV To Kearney 230 kV Ckt #1 overloads in the 2014 off peak case to 111%. The mitigation plan is to reconductor this line by 2014. This project is recommended for approval in the 2010 ISO TP (see table 6-5).

Corsgold-Oakh_Jct 115 kV Ckt #1 Line
The line between Corsgold 115 kV To Oakh_Jct 115 kV Ckt #1 was identified as overloaded with under NERC Category A conditions in the 2019 summer peak case to 110%. The mitigation plan is to reconductor Oakhurst 115 kV tap in the 2015 to 2019 time frame. This plan will be assessed further and included in the next annual ISO transmission plan.

Corcoran 115/70 kV #2 Bank
The Corcoran 115/70 kV #2 Bank was identified as overloaded under NERC Category A conditions in the 2014 and 2019 summer peak case to 105% and 110%, The mitigation plan is to replace the transformer with a higher capacity transformer as soon as practicable. This project was proposed through the request window and was approved in the 2010 ISO TP. In the interim, distribution load in the Corcoran area will be transferred from the 70 kV system to the 115 kV system source.

An alternative project was proposed, by Western Grid Development, LLC but not chosen. The Guernsey 70 kV Energy Storage Project, a reliability-driven battery storage project, was submitted to connect an initially sized 7 MW battery to the Guernsey 70 kV bus. WGD's project would have an initial capital cost of $10.5 million, with additional capital cost of $10.5 million as the battery capabilities are increased over time. The cost of the transformer replacement project was $10-20 million.

Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control and to recover the costs of the facilities through the ISO's TAC. ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition. The ISO staff conducted a technical analysis of the battery storage project and the Corcoran transformer replacement as alternatives to address reliability concerns. ISO staff found that, the analysis provided by the project proponent failed to take into account the Henrietta SPS. Implementation of the proposed storage project would cause voltage collapse when the Henrietta SPS was triggered because the entire 70 kV system in the area would end up radially connected to Corcoran 70 kV source. Potential redesigns to the proposed storage project such as remote tripping of the Corcoran-Guernsey 70 kV line which is counter to ISO guidelines for SPS design. Adoption of the battery storage project would require the addition of two new Special Protection Schemes (SPS). Also, complex operating procedures would need to be developed and closely followed by operators to ensure that the battery was discharged at all times and in exact amounts when needed for reliability and charged only at times and in exact amounts that would not cause reliability problems given the circumstances that exist in this area.

WGD's cost estimates did not account for the cost of the two new SPS mechanisms. Also, if the ISO were to approve the battery storage project, additional costs would still have to be incurred to replace the existing transformer which is extremely old and slated for replacement within the next few years. These additional costs were not included in WGD's cost analysis. The transformer replacement project not only solves the identified reliability need, it replaces the transformer. These cost considerations, it's the simpler design of the transformer replacement project, and the complex operating requirements for the battery project that make the transformer replacement project a superior choice. Therefore, the ISO is rejecting the Guernsey 70 kV Energy Storage Project.

Exchequr-Bervlly 70 kV Ckt #1 Line
The line section between Exchequr 70 kV To Bear Valley substation 70 kV overloads in the 2019 summer peak case immediately following the Mariposa - Exchequr 70 kV #1 line contingency to 108%. The mitigation plan is to reconductor this line section in the 2015 to 2019 time frame. This plan will be assessed further and included in the next annual ISO transmission plan.

Gregg - Ashlan 230 kV #1 Line
The line section between Gregg 230 kV To Figarden T2 230 kV Ckt #1 overloads in the 2019 summer peak case immediately following the Herndon - Ashlan 230 kV #1 line contingency to105%. The mitigation plan is to reconductor Gregg - Ashlan 230 kV #1 line in the 2014 to 2019 time frame. This project was proposed through the 2009 request window and was approved in this ISO transmission plan.

Herndon - Ashlan 230 kV #1 Line
The line section between Herndon 230 kV To Figarden T1 230 kV Ckt #1 overloads in the 2019 summer peak case immediately following the Gregg - Ashlan 230 kV #1 line contingency to 105%. The mitigation plan is to reconductor Herndon-Ashlan 230 kV line in the 2015 to 2019 time frame. This project was proposed through the 2009 request window and was approved in this ISO transmission plan.

Reedley-Dinuba 70 kV Line
The line section between Dinuba_Jt 70 kV To Dinuba 70 kV Ckt #1 overloads in the 2019 summer peak case immediately following the Sand Creek - Orsi Jct 70 kV #1 line contingency to 108%. The mitigation plan is to reconductor Reedley-Dinuba 70 kV line in the 2015 to 2019 time frame. This project was proposed through the 2009 request window and was approved in this ISO transmission plan.

Reedley-Orosi 70 kV Line
The line section between Orosi 70 kV To Orsi Jct 70 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases immediately following the Reedley - Dinuba 70 kV #1 line contingency to 101% and 112%. The mitigation plan is to reconductor Reedley-Orosi 70 kV line by 2013. This project was proposed through the 2009 request window and was approved in this ISO transmission plan.

Los Banos 230/70 kV #3 Bank
The Los Banos 230/70 kV #3 Bank overloads in the 2014 and 2019 summer peak cases immediately following the Los Banos 230/70 kV Bank #4 contingency to 113% and 126%. The mitigation plan is to replace with a higher capacity transformer bank in 2010 as part of a maintenance project.

Certainteed tap 115 kV Line
The line section between Chwchlla 115 kV To Certan T 115 kV Ckt #1 overloads for the Woodward - Chldhosp 115 kV #1 line contingency in the 2019 summer peak case to 101%. The mitigation plan is to rerate Certainteed tap 115 kV in the 2015 to 2019 time frame.

Warnervl-Wilson 230 kV Ckt 1 Line
The line between Warnervl 230 kV to Wilson 230 kV Ckt 1 overloads in the 2014 off peak case immediately following the Gates-Gregg and Gates-McCall double circuit tower line contingency to 101%. The mitigation plan is to install an SPS to trip 2 of 2 Helms pumps in 2014.

Kearney-Herndon 230 kV Ckt #1 Line

The line between Kearney 230 kV To Herndon 230 kV Ckt #1 overloads in the 2014 off peak case immediately following the Wilson-Gregg and Wilson-Borden double circuit tower line contingency to 110%. The mitigation plan is to establish an interim temperature adjusted rating for the 2014 to 2019 time frame.

Panoche-McMulln1 230 kV Ckt #1 Line
The line section between Panoche 230 kV To McMulln1 230 kV Ckt #1 overloads in the summer peak 2014 and 2019 cases for the Helms - Gregg 230 kV #1 and #2 double circuit tower line contingency to 108% and 121%. The mitigation plan is to reconductor the line by 2014. This project is recommended for approval in this ISO transmission plan (see table 6-5).

Helm-McCall 230 kV Ckt #1 Line
The line between Helm-McCall 230 kV Ckt #1 overloads in the 2019 summer peak case immediately following the Gates - Gregg 230 kV #1 and Gates-McCall 230 kV double circuit tower line contingency to 116%. The mitigation plan is to reconductor Helm-McCall 230 kV line by 2014. This project is recommended for approval in this ISO transmission plan (see table 6-5).

Panoche-Helm 230 kV Line
The line between Panoche-Helm 230 kV Ckt #1 overloads in the 2019 summer peak case immediately following the Gates - Gregg 230 kV #1 and Gates-McCall 230 kV double circuit tower line contingency to 119%. The mitigation plan is to reconductor the Panoche-Helm 230 kV line by 2014. This project is recommended for approval in this ISO transmission plan (see table 6-5).

Exchequr-Le Grand 115 kV Ckt #1 Line
The line between Exchequr 115 kV To Le Grand 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases Exchequr - Saxoncrk 70 kV #1 and Merced 115/70 kV Bank #2 overlapping contingency to 110% and 107%. The mitigation plan is to reduce Exchequer, Merced falls, Mcswain after first contingency in 2010.

Barton-Herndon 115 kV Ckt #1 Line
The line between Barton115 kV To Herndon 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases immediately following the Manchester - Herndon 115 kV #1 and Woodward - Chldhosp 115 kV #1 overlapping contingency to 102% and 110%. The mitigation plan is to rerate Barton-Herndon 115 kV line by 2013.

Le Grand-Chowchilla 115 kV Line
The line section between Certan T 115 kV To Le Grand 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases for the Clovis J1 - Sanger 115 kV #1 and Kerckhf2 - Sanger 115 kV #1 overlapping contingency to 121% and 111%. The mitigation plan is to rerate Le Grand-Chowchilla 115 kV line as soon as possible. It is expected that the line can be rerated by 2011.

Manchester-Herndon 115 kV Line
The line between Herndon-Manchester 115 kV Ckt #1 overloads in the 2019 summer peak case immediately following the Helm-McCall and Gates-McCall 230 kV Lines double circuit tower line contingency to 105%. This line also overloads in the 2014 and 2019 summer peak case for the Barton - Herndon 115 kV #1 and Woodward - Chldhosp 115 kV #1 overlapping contingenc yto 103% and 112%. The mitigation plan is to rerate Manchester-Herndon 115 kV line by 2012.

Le Grand-Certainteed 115 kV line section
The line section between Le Grand 115 kV To Certainteed 115 kV Ckt #1 overloads in the 2014 off peak case immediately following the Helm-McCall and Gates-McCall 230 kV lines double circuit tower line contingency to 108%. The mitigation plan is to reconductor this line by 2014. This project is recommended for approval in this ISO transmission plan (see table 6-5).

Mitigation of transmission constraints during the off-peak period between 2010 and 2013 will be through the continued implementation of existing operational restrictions on pumping with the Helms Pumped Storage project described in ISO Operating Procedure T-129.

Overlapping Contingencies Requiring Load Curtailment

The following facilities are overloaded in the 2014 and /or 2019 summer peak cases for the overlapping contingencies shown. The mitigation plan is to establish a 15 minute rating and an operating procedure and install necessary SCADA to curtail load within 15 minutes after the second contingency. The necessary implantation date is shown below. If SCADA installation is required the implantation date may need to be moved from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Table 3-3.6.6: Overlapping contingencies requiring load curtailment

Overloaded Facility	Overlapping Contingency	Implementation date
Bank between Herndon 115 kV To Herndon 115 kV Ckt #1	Herndon 230/115 kV Bank #2 and Herndon 230/15 kV Bank #3	2010
Bank between Herndon 115 kV To Herndon 115 kV Ckt #2	Herndon 230/115 kV Bank #1 and Herndon 230/15 kV Bank #3	2010
Bank between Herndon 230 kV To Herndon 115 kV Ckt #1	Herndon 230/115 kV Bank #2 and Herndon 230/15 kV Bank #3	2010
Bank between Herndon 230 kV To Herndon 115 kV Ckt #2	Herndon 230/115 kV Bank #1 and Herndon 230/15 kV Bank #3	2010
Bank between Herndon 230 kV To Herndon 115 kV Ckt #3	Herndon 230/115 kV Bank #1 and Herndon 230/115 kV Bank #2	2010
Line between Calfax 70 kV To Schlndlr 70 kV Ckt #1	Gats2_tp 70 kV - Colinga2 70 kV #1 and Gates 230115 kB Bank #1	2010
Line between Danishcm 115 kV To Cal Ave 115 kV Ckt #1	Cal Ave - Sanger 115 kV #1 and Wst Frso - Mc Call 115 kV #1	2010
Line between Kings_J1 115 kV To Kings J2 115 kV Ckt #1	Mc Call - Gaurd J2 115 kV #1 and Kingsburg - Gwf Hep 115 kV #1	2010
Line between Kingsburg 115 kV To Gaurd J1 115 kV Ckt #1	KcognJct - Kingsbrg 115 kV #1 (Drop Kingsburg Unit 1) and Kingsburg - Gwf Hep 115 kV #1	2010
Line between Mc Call 115 kV To Danishcm 115 kV Ckt #1	Cal Ave - Sanger 115 kV #1 and Wst Frso - Mc Call 115 kV #1	2010
Line between Mc Call 115 kV To Gaurd J1 115 kV Ckt #1	KcognJct - Kingsbrg 115 kV #1 (Drop Kingsburg Unit 1) and Kingsburg - Gwf Hep 115 kV #1	2010
Line between Reedley 115 kV To Piedra_1 115 kV Ckt #1	SngrJct - Reedley 115 kV #1 (Drop Sangerco Unit 1) and Mc Call - Wahtoke 115 kV #1	2010
Line between Sanger 115 kV To Cal Ave 115 kV Ckt #1	Mc Call - Danishcm 115 kV #1 and Wst Frso - Mc Call 115 kV #1	2010
Line between Sanger 115 kV To Cal Ave 115 kV Ckt #1	McCall-West Fresno & Mc Call - California	2010
Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson A - Wilson B 115 kV #1 and Wilson 230kV/Wilson B 115 kV Bank #2	2010
Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson B - El Captn 115 kV #1 and Wilson B - Merced 115 kV #2	2010
Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson A - Merced 115 kV #1 and Wilson B - El Captn 115 kV #1	2010
Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson-Atwater and El Capitan-Wilson	2010
Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #1	McCall 230/115 kV Bank #2 and McCall 230/115 kV Bank #3	2011

Table 3-3.6.6: Overlapping Contingencies Requiring Load Curtailment (cont'd)

Overloaded Facility	Overlapping Contingency	Implementation date
Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #3	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #2	2011
Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #1	McCall 230/115 kV Bank #2 and McCall 230/115 kV Bank #3	2011
Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #3	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #2	2011
Line between Atwater 115 kV To Wilson A 115 kV Ckt #1	Atwater - Merced 115 kV #1 and Wilson B - El Captn 115 kV #1	2011
Line between Exchequr 70 kV To Mcswainj 70 kV Ckt #1	Borden-Gregg (Drop Helms Unit 3) and Exchequr - Le Grand 115 kV #1 (Drop 34306 Unit 1)	2011
Line between San Migl 70 kV To Psa Rbls 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	2011
Line between San Migl 70 kV To Psa Rbls 70 kV Ckt #1	Colnga 1 -Jacalito 70 kV #1 and Colnga 2 to Tornado 70 kV #1 (Drop Chv Coal Unit 1)	2011
Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #2	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #3	2012
Line between Mc Call 115 kV To Wst Frno 115 kV Ckt #1	Mc Call - Danishcm 115 kV #1 and Cal Ave - Sanger 115 kV #1	2012
Line between Ortiga 70 kV To Mrcysprs 70 kV Ckt #1	Oro Loma - Dos Pals 70 kV #1 and Livngstn - Los Banos 70 kV #1	2012
Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #2	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #3	2013
Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Atwater - Cresey T 115 kV #1 and Wilson B - Merced 115 kV #2	2013
Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson - Atwater 115 kV #1 and Wilson B - Merced 115 kV #2	2013
Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Atwater - Cresey T 115 kV #1 and Wilson A - Merced 115 kV #1	2013
Line between Kings J2 115 kV To Kingsburg 115 kV Ckt #1	Mc Call - Gaurd J2 115 kV #1 and Kingsburg - Gwf Hep 115 kV #1	2014
Line between Ortiga 70 kV To Mrcysprs 70 kV Ckt #1	Livngstn - Los Banos 70 kV #1 and Canal - Santa Rta 70 kv #1	2014
Line between Templ_J 70 kV To Psa Rbls 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	2014
Line between Templt7 70 kV To Templ_J 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	2014
Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson - Atwater 115 kV #1 and Wilson A - Merced 115 kV #1	2014

Table 3-3.6.6: Overlapping Contingencies Requiring Load Curtailment (cont'd)

Overloaded Facility	Overlapping Contingency	Implementation date
Line between Borden 70 kV To Cassidy 70 kV Ckt #1	Mc Call - Wahtoke 115 kV #1 and Frantdm GSU	2015
Line between Borden 70 kV To Cassidy 70 kV Ckt #1	Frantdm GSU and Tvy Vlly - Reedley 70 kV #1	2015
Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson - Atwater 115 kV #1 and Wilson A - Wilson B 115 kV #1	2015
Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson B - Merced 115 kV #2 and Merced 115/70 kV Bank #2	2015

Voltage Concerns Mitigations

The DINUBA 70 kV bus experiences low voltages in the 2014 and 2019 summer peak case immediately following the Reedley - Dinuba 70 kV #1 line contingency to 0.91 and 0.89 per unit. The mitigation plan to reconductor Reedley-Orosi 70 kV line, recommended for approval, is expected to reduce the line impedance sufficiently to improve the voltage to an acceptable level.

The STOREY 2 230 kV and BORDEN 230 kV buses experience low voltages in the 2014 and 2019 summer peak cases immediately following the Borden-Gregg 230 kV #1 and L-1 Wilson-Gregg 230 kV #1 double circuit tower line contingency of 0.9 and 0.88 per unit. The mitigation plan is to install reactive support at Borden in 2014. This plan will be assessed further and included in the next annual ISO transmission plan.

The ANGIOLA 70 kV and nearby busses experience low voltages in the 2014 and 2019 summer peak cases immediately following the McCall-Kingsburg 230 kV #1 and L-1 McCall-Kingsburg 230 kV #2 double circuit tower line contingency to 0.89 and 0.86 per unit. The mitigation plan, recommended for approval, to replace the 115/70 kV Corcoran transformer with a larger capacity and lower impedance transformer is expected to sufficiently improve the voltage to an acceptable level.

3.3.6.5 Key Conclusions

Based on the ISO study assessment, the Fresno Area had:

- Seven overloads under normal conditions;
- Seven overloads caused by seven critical single contingencies under summer peak conditions and seven overloads caused by four single contingencies under summer off-peak conditions; and
- Numerous overloads caused by numerous critical multiple contingencies under summer peak and off-peak conditions.

The ISO proposed solutions to address all of the identified overloads and received seven project proposals through the request window and operational solutions were submitted by PG&E for the remaining overloads:

- Four request window projects were approved;
- In addition to the four Fresno area projects being approved under this plan, ISO Management will be seeking Board approval, of several more reliability projects for the Fresno area at the March 2010 Board meeting. These projects originated prior to the 2010 Transmission Plan in the Central California Clean Energy Transmission Project (C3ETP) planning process.

The Guernsey 70 kV Energy Storage Project, proposed by Western Grid Development, LLC, was rejected for the reasons previously described.

Western Grid Development, LLC proposed another battery storage reliability-driven project, the Coppermine 70 kV Energy Storage Project, to address reliability concerns in the Greater Fresno area. Western Grid Development, LLC proposed to build and own the battery storage projects, to turn the facilities over to the ISO's operational control and to recover the costs of the facilities through the ISO's TAC. However, ISO tariff section 24.1.2 provides that that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

On September 30, 2008, PG&E completed a Coppermine-Tivy Valley-Reedley 70 kV reconductoring maintenance project. This project resolved previously identified reliability concerns in the area. Thus, the ISO is rejecting the Coppermine 70 kV Energy Storage Project because there is no need for this project or any other project in the area.

3.3.7.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

Thermal Overload Mitigations

Kern PP 230/115 kV #3 Bank

The Kern PP 230/115 kV #3 and 3a Bank piggybacked transformer banks overload in the 2014 and 2019 summer peak cases immediately following the kern pp 230/115 ckt 4 and kern pp 230/115 ckt 5 overlapping contingency to 134% and 156%. The mitigation plan is to Replace banks 3 and 3a with a 420 MVA transformer in 2012 as part of a maintenance project. The interim mitigation plan for 2010 and 2011 is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency. If SCADA installation is required then the interim plan implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Midway 230/115 kV #2a Bank

The Midway 230/115 kV #2a Bank transformer bank overloads in the 2014 and 2019 summer peak cases immediately following the midway 230/115 ckt 1 and midway 230/115 ckt 3 overlapping contingency to 101% and 105%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2013.

Taft 115/70 kV #2 Bank

The Taft 115/70 kV #2 Bank transformer bank overloads in the 2014 and 2019 summer peak cases immediately following the Taft 115/70 ckt 1 and slr-tann g-1 overlapping contingency to 103% and 105%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the interim plan implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Stckdl Jt-Midway 230 kV Ckt #1 Line

The line section between Stckdl Jt 2 230 kV To Midway 230 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases immediately following the Midway-Kern #1 and #4 230 kV double circuit tower line outage to 101% and 118%. The mitigation plan is to rerate this section of Midway-Kern No. 3 230 kV line by 2013.

Semitropic-Midway 115 kV Ckt #1 Line

The line between Semitropic 115 kV To Midway 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases immediately following the Midway-Smyrna 115 and Famoso-Cawelo 115 overlapping line contingency to 124% and 127%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Westpark-Kern Pwr 115 kV Ckt #1 Line

The line between Westpark 115 kV To Kern Pwr 115 kV Ckt #1 overload in the 2019 summer peak case for the Westpark-Kern pwr 115 ckt 2 and Kern pwr-Magunden 115 overlapping contingency to 103%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2015.

Westpark-Kern Pwr 115 kV Ckt #2 Line
The line between Westpark 115 kV To Kern Pwr 115 kV Ckt #2 overload in the 2019 summer peak case for the Westpark-Kern pwr 115 ckt 1 and Kern pwr-Magunden 115 overlapping contingency to 103%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2015.

Ganso-Midway 115 kV Ckt #1 Line
The line between Ganso 115 kV To Midway 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases for the Midway-Semitropic 115 and Famoso-Cawelo 115 overlapping contingency to 111% and 114%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Midway-Navy 35R 115 kV Ckt #1 Line
The line between Midway 115 kV To Navy 35R 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases for the Taft-University 115 and Fellows-Taft 115 overlapping contingency to 117% and 116%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011.

Voltage Concerns Mitigations

- No voltage concerns were identified.

3.3.7.5 Key Conclusions

Based on the ISO study assessment, the northern Kern Area had:

- No overloads or voltage concerns under normal conditions;
- No overloads or voltage concerns under single contingency conditions; and
- Numerous overloads caused by numerous critical multiple contingencies under summer peak conditions.

Some of the overloads will be resolved by a planned maintenance project to upgrade the 230/115 kV transformers at Kern PP switchyard. For the remaining overloads, the ISO proposed operational solutions.

Western Grid Development, LLC proposed a battery storage reliability-driven project, the Weedpatch 70 kV Energy Storage Project, to address reliability concerns in the Kern area. The initial capital cost of the Weedpatch project is $4.5 million, with additional capital costs to be incurred as the battery capabilities are increased. Western Grid Development, LLC proposed to build and own the battery storage projects, to turn the facilities over to the ISO's operational control. However, ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territiry in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO results posted on September 15, 2009 that showed overloads in the Weedpatch area were flawed due to incorrect modeling information that did not reflect an existing operating procedure to open the Weedpatch CB42 breaker during the summer.

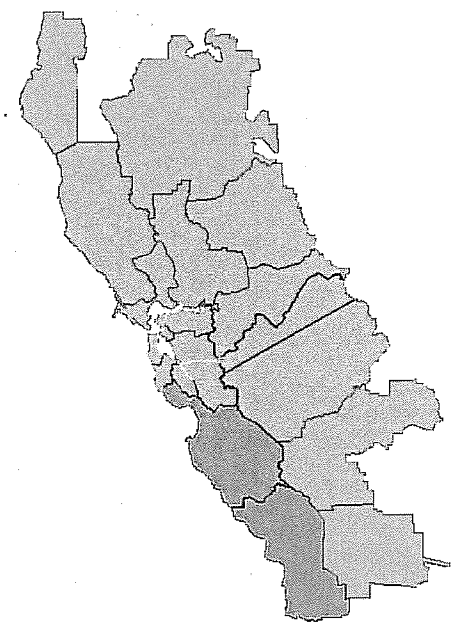
The correct results with this operating procedure to open the Weedpatch CB 42 have been reflected in this report. This correction addresses the Weedpatch area overloads. Thus, neither the Weedpatch 70 kV Energy Storage Project, nor any other transmission project, is needed because there is no identified reliability need in this area.

3.3.8 Central Coast and Los Padres Areas

3.3.8.1 Area Description

The Central Coast Area (i.e., Central Coast) is located south of the Greater Bay Area and extends along the Central Coast from Santa Cruz to King City. The Central Coast transmission system serves Santa Cruz, Monterey and San Benito counties. The green shaded portion in the figure below depicts the geographic location of the Central Coast and Los Padres areas.

The Central Coast electric transmission system is comprised of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Most of the customers in the Central Coast are supplied via local transmission system out of the Moss Landing power plant substation. The local transmission systems are: a) Santa Cruz - Watsonville, Monterey - Camel and Salinas - Soledad - Holister sub-areas which are supplied via 115 kV double circuit tower lines (DCTL), b) King City, an area supplied by 230 kV lines from the Moss Landing and Panoche substations and c) Burns - Point Moretti sub-area which is supplied by a 60 kV line from the Monta Vista substation in Cupertino. Besides the 60 kV connection between the Salinas and Watsonville substations, the only connection among the sub-areas is at the Moss Landing substation. The Central Coast transmission system is tied to the San Jose and De Anza systems in the north, and the Greater Fresno system in the east.



The Los Padres Division is located in the southwestern portion of PG&E's service territory (south of the Central Coast division). San Luis Obispo, Santa Maria, Paso Robles and Atascadero are among the cities PG&E provides electric service to within this Division. The City of Lompoc, a member of the Northern California Power Authority (NCPA) is also located here. Counties in the area include San Luis Obispo and Santa Barbara. The Diablo Canyon nuclear power plant is also located in Los-Padres. Most of the power generated from the Diablo Canyon power plants are exported to the north and east through bulk 230 kV and 500 kV transmission lines, hence it has very little impact on the Los Padres area operation. There are several transmission ties to the Fresno and Kern systems, with the majority of these interconnections at the Gates and Midway substations. Local customer demand is served through a network of 115 kV and 70 kV circuits.

Load forecasts indicate that the Central Coast and Los Padres areas should reach their summer peak demand of 872 MW and 740 MW respectively by 2014. By 2019 the loading for these two areas would be 907 MW and 779 MW, respectively. Load is increasing at a rate of approximately nine to 10 MW per year (1.1%). Winter peak demands in the Central Coast are also expected to grow, albeit at a lower rate than the summer peak demands and the expected peak load forecast for 2014 and 2019 are approximately 845 MW and 868 MW, respectively. As this area is along the coast, it has a dominant winter-peak profile, (e.g., the Monterey - Carmel sub-area). Winter peak demands could be as high as 10% more than summer peak demands.

Accordingly, system assessments in these areas included technical studies using load assumptions for these summer and winter peak conditions. Table 3-3.8.2 includes load forecast data for both areas.

The scenario 2 contingency analysis results for Category B and DCTL contingencies showed no new facility overloads in the 2024 assessment. Based on this result it can be concluded that with the scenario 2 mitigations proposed in Table 7-2, the GBA bulk transmission system will have sufficient thermal load serving capability to serve the projected 2024 load if all existing thermal overloads are addressed with projects or operating solutions approved through the annual transmission plan process.
The next limiting facilities identified are Tracy and Tesla 500/230 kV transformers banks which would potentially overload around year 2026 for corresponding worst Category B contingencies.

In terms of the voltage load serving capability for the year 2024, the GBA bulk transmission system will need about 1000 MVAR of additional reactive support to satisfy the WECC voltage criteria under this scenario.

Scenario 3
The scenario 3 contingency analysis results for Category B and DCTL contingencies showed no new facility overloads in the 2024 assessment. Based on this result it can be concluded that with the scenario 3 mitigations proposed in Table 7-2, the GBA bulk transmission system will have sufficient thermal load serving capability to serve the projected 2024 load if all existing thermal overloads are addressed with projects or operating solutions approved through the annual transmission plan process.
In terms of the voltage load serving capability, the GBA bulk transmission system exhibits sufficient capability under this scenario to serve the projected 2024 load.

7.2.4 Conclusion

About 86% of the Category B and 70% of the Category C overloads identified in this study are existing facility overloads. These overloads were also identified in the GBA annual reliability assessment. Based on this finding it can be concluded that the majority of potential facility overloads within the GBA are not sensitive to the level of internal GBA generation. The new category B thermal overloads identified in the high and medium GBA new generation scenarios are due to the location of the selected new generation and are specific to that particular new generation.

Apart from the mitigation solutions proposed in Table 7-2, other facility upgrades, as identified in the annual reliability assessment (listed in section 3.3.5.3) will also be needed in order to achieve sufficient thermal capability through 2019 under normal, single facility outage and DCTL outage conditions. Also, specific to the scenario 1, upgrades to the Newark 230/115 kV transformer bank and Contra Costa-Birds Landing 230 kV line will be needed in order to have sufficient thermal load serving capability through 2024; whereas, the scenarios 2 and 3 do not require any additional facility upgrades to achive sufficient thermal capability through 2024.

In conclusion, based on the analyses performed here, the GBA bulk transmission system does not appear to have an urgent need for a large reliability upgrades. In terms of the thermal and voltage capabilities, it appears that the GBA bulk transmission system will have sufficient thermal capability to serve the GBA load until about 2024 with some relatively smaller facility upgrades. Whereas, in terms of voltage, the system appears to have sufficient capability to serve the GBA load until about 2019 with approximately 300 MVAR of additional reactive power support. With no new local generation added, the GBA bulk transmission system will need approximately 1000 MVAR of additional reactive support to serve the GBA load until around 2024 satisfying the WECC voltage requirements.

The conclusions drawn here are entirely based on the studies performed for the summer peak loading conditions and the three GBA new generation scenarios. Furthermore, these conclusions are drawn strictly from the reliability planning perspective. Additional studies may be needed to evaluate the GBA bulk transmission upgrade needs from the economic and the renewable transmission planning perspectives that will likely be developed in the comprehensive plan for renewables integration. In that regard, the ISO economic planning study for GBA has identified congestion on some GBA bulk transmission facilities predominantly during off-peak loading and high wind dispatch scenario associated with the Solano competitive renewable energy zone (CREZ). The base case used for this economic study was targeted to meet the 33% renewable portfolio standards (RPS) and hence was modeled with a high concentration of wind generation (about 1000 MW) in Solano area. Details of this study and the economic planning study will be published on the ISO website.

7.3 City of San Francisco System Reliability Anaysis

7.3.1 Summary

Since the retirement of the Hunters Point Power facility, a great deal of focus has been placed on developing a transmission plan that would result in the retirement of all generation at the Potrero Power Plant facility. Over the past several years, a great deal of work has been done to complete the installation of the Trans Bay Cable Project that, once in service, will transfer up to 400 MW of electricity from the Pittsburg area to the San Francisco area. Past studies performed by the ISO had determined that once the Trans Bay Cable Project was placed into service and proven reliable, it would provide enough electrical capacity into the San Francisco area to eliminate the RMR requirement for Potrero Unit 3. However, lacking other transmission infrastructure improvements within San Francisco, the need for Potrero Units 4, 5, and 6 remained.

Past studies for San Francisco had indicated that approximately 150 MW of generation would be needed in the City to ensure system reliability while allowing for an expected load growth of about 1% (~10 MW) per year. However, since the ISO conducted its earlier analysis, two key assumptions used in that earlier analysis were modified:

1. PG&E adjusted ten-year load forecast was reduced to 0.6%/year as compared to their historical projection of 1%/year;
2. PG&E provided updated new cable ratings for their recabling project (Martin-BayShore-Potrero #1 and #2) that were significantly higher than the prior ratings established for this project.

ISO reviewed these modifications provided by PG&E and found them reasonable. After adjusting for the above assumptions and assuming Trans Bay Cable is in service and proven reliable and the recabling project completed, the study revealed that Potrero Units 4, 5, and 6 can be released from their RMR designation. Further, analysis of PG&E's Embarcadero - Potrero 230 kV cable was also performed, which shows that this cable is not needed within the ten year planning horizon covered by the Transmission Plan. This project can be re-evaluated at a later time should any significant changes in the planning assumptions occur.

7.3.2 Key Assumptions

- Study years: 2010, 2014, 2019 and selected future years
- Extreme weather forecast (1 in 10) for SF and Peninsula
- Updated Cable ratings in SF provided by PG&E
- TransBay Cable (TBC) in service
- Potrero Unit 3 out of service
- Potrero Units 4, 5, and 6 in service

Study Scenarios

- Martin-Bayshore-Potrero re-cabling (2010 study)
- No Generation at Potrero
- 150 MW Generation at Potrero
- With and Without new Embarcadero-Potrero 230 kV cable (2014, 2019)

Contingencies

For the San Francisco and Peninsula areas, all 60 kV to 230 kV facilities were taken out of service, one at a time for Category B, and N-1-1, bus faults, and double circuit tower line outages for Category C. To meet ISO planning standard for Category B, selected generator and line outages (G-1, L-1) were also evaluated.

7.3.3 Results

Martin-Bayshore-Potrero re-cabling

A single line diagram of San Francisco's transmission system is shown in Figure 7-1. The Martin-Bayshore-Potrero cables #1 and #2, identified as AHW-1 and AHW-2 respectively in Figure 7-1, are more than 50 years old and are currently undergoing re-cabling with higher capacity cables. AHW-2 is currently out of service and is scheduled to be back in service after re-cabling by April 2010. AHW-1 will then be taken out of service for re-cabling and it will be back in service by November 2010. Completion of AHW-2 is on schedule.

By the summer of 2010, it is expected that AHW-2 will be in service with higher ratings and AHW-1 will be out of service for recabling. The Trans Bay Cable will be in service. Potrero peaker units #4, #5 and #6 are assumed off-line.

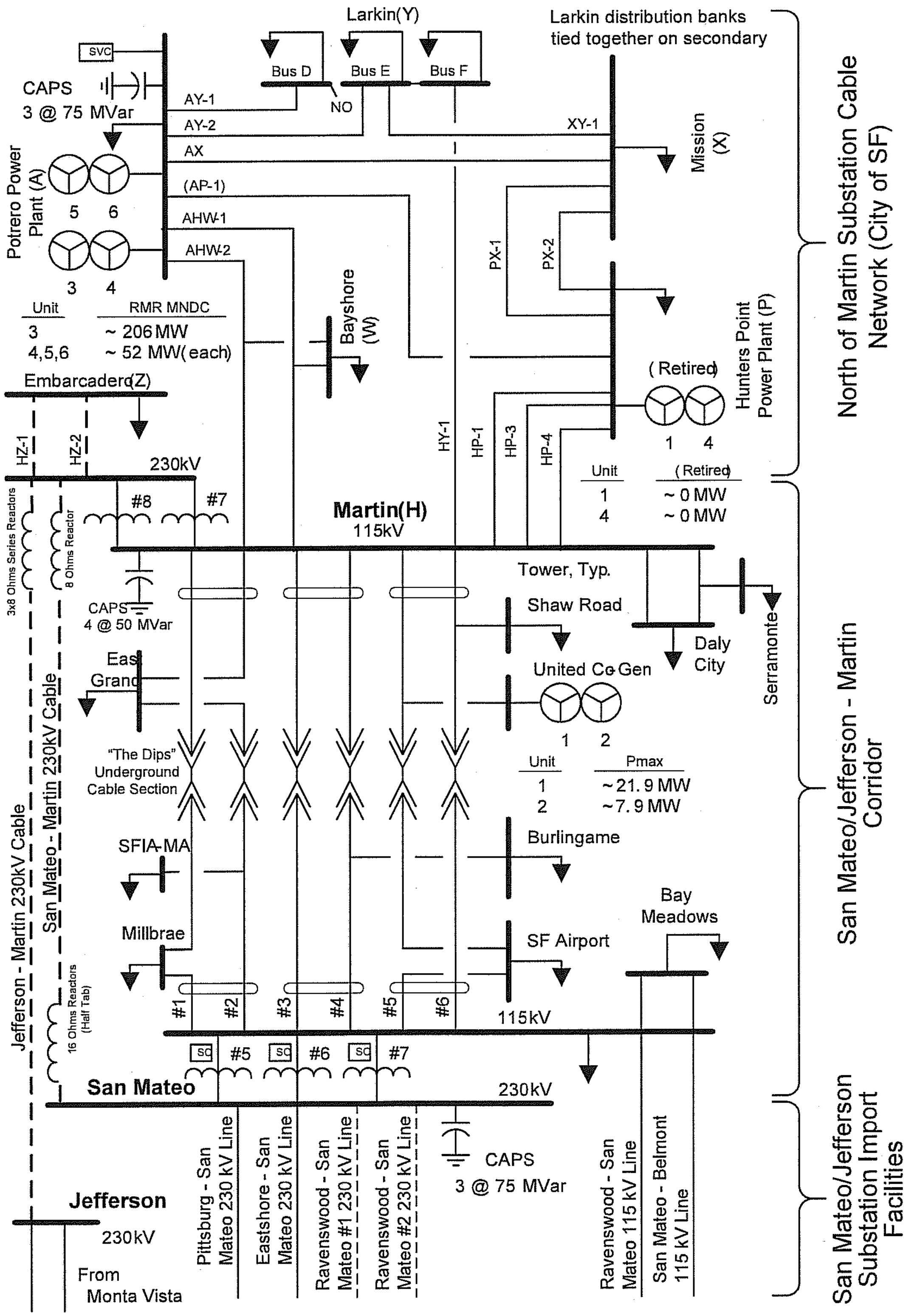


Figure 7-1: San Francisco system one-line diagram

Table 7-3 shows the results of Category B outages for this scenario. The results show that no transmission facilities in San Francisco will be overloaded under Category B contingency conditions. All facilities remain within their applicable ratings. It should be noted that Mission-Potrero 115 kV circuit is loaded to 99.4% of its emergency rating. Should an overload occur, the proposed DC runback mitigation scheme placed into service with the Trans Bay Cable will be implemented to ramp down the output of Trans Bay Cable from 400 MW to 200 MW to relieve this overload.

Table 7-3: 2010 Heavy Summer--Martin-Bayshore-Potrero #1 out
Trans Bay Cable In; Potrero Unit 3 Out; Potrero Units 4, 5, and 6 Out
Category B Outages

Facility					Worst Contingency	2010 LOADING
MISSON	115	POTRERO	115	#1	Potrero-Larkin E 115 kV line	99.4%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission 115 kV line	86.1%
LARKIN F	115	LARKIN 2	12	#6	Potrero-Larkin D 115 kV line	85.9%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission 115 kV line	85.4%
LARKIN E	115	LARKIN 2	12	#4	Martin C-Larkin F 115 kV line	83.4%
LARKIN F	115	LARKIN 1	12	#5	Potrero-Larkin D 115 kV line	82.8%
LARKIN E	115	LARKIN 1	12	#3	Martin C-Larkin F 115 kV line	82.1%
MARTIN C	115	HNTRS PT	115	#3	Trans Bay Cable	81.9%
MARTIN C	115	HNTRS PT	115	#1	Trans Bay Cable	81.3%
LARKIN D	115	LARKIN 2	12	#2	Martin C-Larkin F 115 kV line	81.2%
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission 115 kV line	80.6%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D 115 kV line	78.5%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission 115 kV line	77.3%
MARTIN C	115	BAYSHOR2	115	#2	Trans Bay Cable	76.7%
BAYSHOR2	115	POTRERO	115	#2	Trans Bay Cable	71.0%

Table 7-4 shows Category C results for the condition when AHW-1 is out for re-cabling, TBC is in service and Potrero units 4, 5, and 6 are off line. For this condition, significant overloading of transmission facilities in San Francisco will occur which will require developing mitigation plans to address these overloads. Further analysis demonstrated that these overloads were largely independent of generation at Potrero; as such, mitigation plans will be needed.

Table 7-4: 2010 Heavy Summer--Martin-Bayshore-Potrero #1 out
Trans Bay Cable In; Potrero Unit 3 Out; Potrero Units 4, 5, and 6 Out
Category C Outages

Facility					Worst Contingency	2010 LOADING
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission and Larkin F-Martin 115 kV	171.5%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission and Potrero-Hunters point 115 kV	102.2%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission and Potrero-Larkin D 115 kV	170.0%
MARTIN C	115	HNTRS PT	115	#3	TransBay Cable and Martin-Hunters Point #1 115 kV	114.7%
MARTIN C	115	HNTRS PT	115	#1	TransBay Cable and Martin-Hunters Point #3 115 kV	111.4%
MISSON	115	POTRERO	115	#1	Potrero-Larkin D and Potrero-Larkin E 115 kV	123.6%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission and Larkin F-Martin 115 kV	175.2%
LARKIN D	115	LARKIN 2	12	#2	Larkin E-Mission and Larkin F-Martin 115 kV	176.1%
LARKIN E	115	LARKIN 1	12	#3	Potrero-Larkin D and Larkin F-Martin 115 kV	175.6%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D and Larkin F-Martin 115 kV	175.2%
LARKIN F	115	LARKIN 1	12	#5	Larkin E-Mission and Potrero-Larkin D 115 kV	176.4%
LARKIN F	115	LARKIN 2	12	#6	Larkin E-Mission and Potrero-Larkin D 115 kV	173.9%

Table 7-5 shows Category C results with Potrero units 4, 5 and 6 online and generating at full 150 MW. All other assumptions remain the same. These results show that only Martin-Hunters Point 115 kV lines #1 and #3 will no longer be overloaded. All other facilities will remain overloaded for Category C outages. These results show that Potrero Units 4, 5, 6 have negligible impact on addressing Category C outages, as such, the ISO has determined these units could be released from their RMR obligations under this scenario.

Table 7-5: 2010 Heavy Summer--Martin-Bayshore-Potrero #1 out
Trans Bay Cable In; Potrero Unit 3 Out; Potrero Units 4, 5, and 6 In
Category C outages

Facility					Worst Contingency	2010 LOADING
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission and Larkin F-Martin 115 kV	171.5%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission and Potrero-Larkin D 115 kV	169.9%
MISSON	115	POTRERO	115	#1	Potrero-Larkin D and Potrero-Larkin E 115 kV	144.2%
POTRERO	115	LARKIN E	115	#2	Potrero-Mission and Potrero-Hunters point 115 kV	143.0%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission and Larkin F-Martin 115 kV	175.2%
LARKIN D	115	LARKIN 2	12	#2	Larkin E-Mission and Larkin F-Martin 115 kV	176.1%
LARKIN E	115	LARKIN 1	12	#3	Potrero-Larkin D and Larkin F-Martin 115 kV	175.6%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D and Larkin F-Martin 115 kV	175.2%
LARKIN F	115	LARKIN 1	12	#5	Larkin E-Mission and Potrero-Larkin D 115 kV	176.4%
LARKIN F	115	LARKIN 2	12	#6	Larkin E-Mission and Potrero-Larkin D 115 kV	173.9%

With and without the new Embarcadero-Potrero 230 kV cable

A single line diagram showing the proposed 230 kV cable (highlighted) from the Embarcadero 230 kV substation to Potrero 115 kV substation with a 230/115 kV transformer at the Potrero substation is shown in Figure 7-2 below. The purpose of this project was to increase the load serving capability of San Francisco and enhance reliability of the San Francisco electric system, in particular the Embarcadero load center. This project was evaluated in the five and 10 year planning horizon (2014 and 2019).

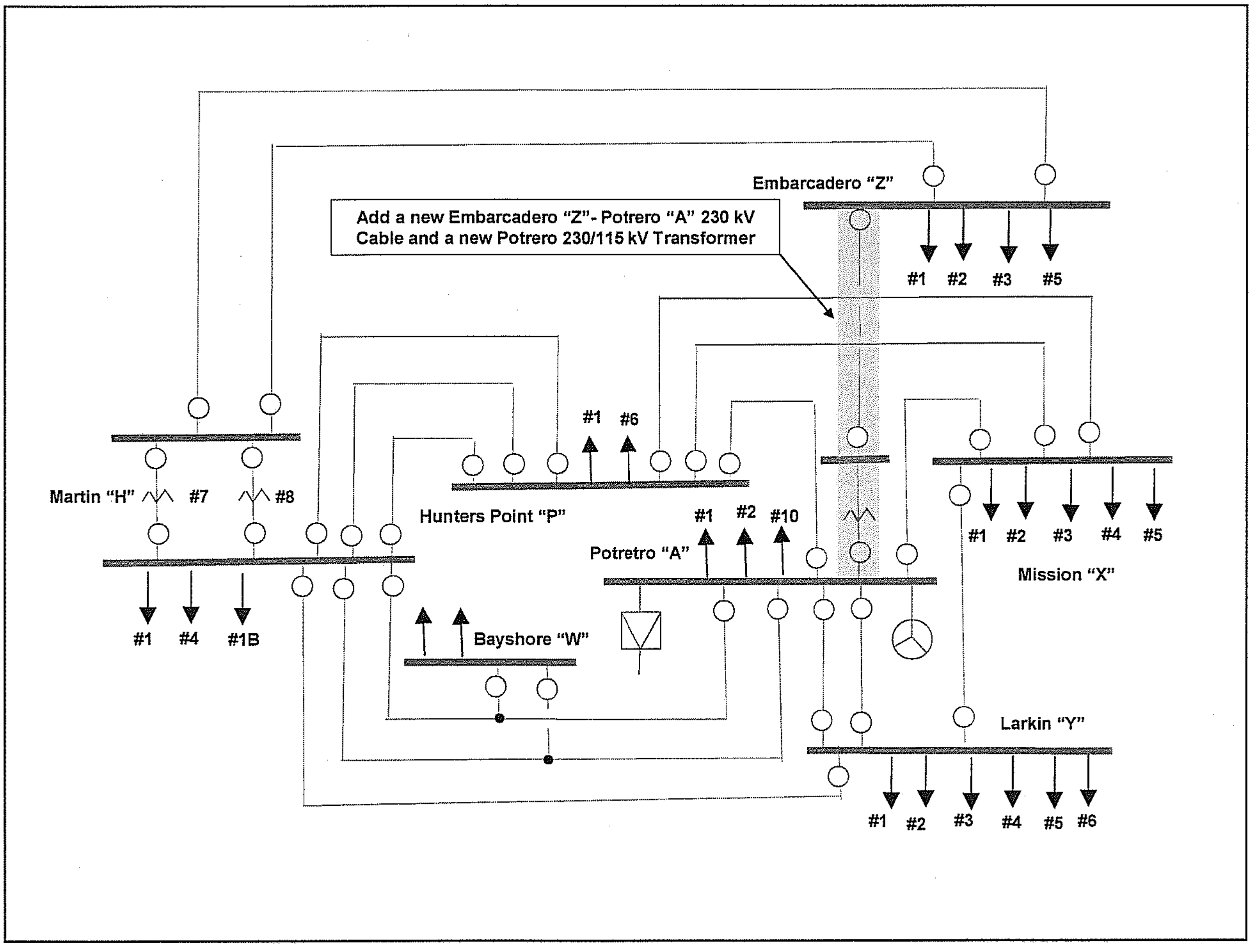


Figure 7-2: Embarcadero-Potrero 230 kV cable

The Embarcadero substation is currently served by Martin substation through two 230 kV underground cables between Martin and Embarcadero. The loss of both cables will result in loss of approximately 95% (260 MW) of Embarcadero substation load. The remaining 5% would continue to be served through the 12 kV distribution system. Analysis has shown that all of the Embarcadero substation load can be served by restoring one of the Martin – Embarcadero 230 kV circuits to service. Analysis also shows that the proposed Embarcadero – Potrero 230kV line will prevent loss of Embarcadero substation load should both Martin – Embarcadero 230kV circuits be lost. However, from the perspective of NERC and WECC Planning standards, loss of two circuits constitutes a Category C contingency for which load dropping is allowed.

Table 7-6 below shows the San Francisco transmission system performance under Category B outages for no generation at Potrero and no new Embarcadero-Potrero cable. Loading of facilities in 2014 and 2019 is identified. Only one circuit, Mission-Potrero 115 kV line, is slightly overloaded. As mentioned earlier, this overload can be mitigated through a DC runback scheme on the Trans Bay Cable. All other facilities are well within their applicable ratings. The next heavily loaded line is at 90% level increasing only at a rate of about 1% in five years. This table indicates that San Francisco transmission system, without the new Embarcadero-Potrero cable, is quite robust and will serve the City's electric demand well beyond 2019 under all possible Category B contingencies.

Table 7-6: No generation at Potrero; No Embarcadero-Potrero 230 kV Cable
Trans Bay Cable In; Recabling Project Complete
Category B outages

Facility					Worst Contingency	LOADING	
						2014	2019
MISSON	115	POTRERO	115	#1	Potrero-Larkin E 115 kV line	102.2%	103.2%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission 115 kV line	89.6%	90.4%
LARKIN F	115	LARKIN 2	12	#6	Potrero-Larkin D 115 kV line	87.1%	88.6%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission 115 kV line	86.7%	88.2%
LARKIN E	115	LARKIN 2	12	#4	Martin C-Larkin F 115 kV line	84.5%	86.0%
LARKIN F	115	LARKIN 1	12	#5	Potrero-Larkin D 115 kV line	83.9%	85.4%
LARKIN E	115	LARKIN 1	12	#3	Martin C-Larkin F 115 kV line	83.2%	84.7%
LARKIN D	115	LARKIN 2	12	#2	Martin C-Larkin F 115 kV line	82.4%	83.8%
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission 115 kV line	81.9%	83.3%

Table 7-7 below shows the results for San Francisco transmission system under Category C outages. Among more than 100 Category C outages evaluated, these are the most severe L-1-1 contingencies causing overloads. Most of the transmission facilities including transformers are severely overloaded and can be mitigated through transferring loads to other substations, decreasing output of the TransBay cable and in extreme cases, possible load dropping. ISO staff is working with PG&E staff to finalize mitigation plans before the summer of 2010.

Table 7-7: No generation at Potrero; No Embarcadero-Potrero 230 kV Cable
Trans Bay Cable In; Recabling Project Complete
Category C outages

Facility					Worst Contingency	LOADING	
						2014	2019
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission and Larkin F-Martin 115 kV	174.5%	178.0%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission and Potrero-Larkin D 115 kV	173.3%	177.0%
MISSON	115	POTRERO	115	#1	Potrero-Larkin D and Potrero-Larkin E 115 kV	124.7%	126.1%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission and Potrero-Hunters point 115 kV	102.1%	102.7%
LARKIN F	115	LARKIN 1	12	#5	Larkin E-Mission and Potrero-Larkin D 115 kV	179.4%	183.1%
LARKIN D	115	LARKIN 2	12	#2	Larkin E-Mission and Larkin F-Martin 115 kV	179.0%	182.5%
LARKIN E	115	LARKIN 1	12	#3	Potrero-Larkin D and Larkin F-Martin 115 kV	178.5%	182.0%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission and Larkin F-Martin 115 kV	178.0%	181.5%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D and Larkin F-Martin 115 kV	178.0%	181.5%
LARKIN F	115	LARKIN 2	12	#6	Larkin E-Mission and Potrero-Larkin D 115 kV	176.8%	180.2%

Tables 7-8 and 7-9 below show the results for San Francisco transmission system for Category B and Category C outages with new Embarcadero-Potrero 230 kV cable in service. The results are very similar to those shown in Tables 7.6 and 7.7. Mission-Potrero overload in Table 7.8 is slightly higher than it is in Table 7.6, however, it can be mitigated through the DC runback scheme.

Comparing the results of without and with Embarcadero-Potrero cable, it appears that Embarcadero-Potrero cable provides no technical benefit to the system in terms of either eliminating some overloads, or reducing overload levels.

The bus voltages in San Francisco under all Category B and Category C outages are satisfactory and within the allowable NERC and WECC voltage criteria.

Table 7-8: No generation at Potrero; Embarcadero-Potrero 230 kV Cable added
Trans Bay Cable In; Recabling Project Complete
Category B outages

Facility					Worst Contingency	LOADING	
						2014	2019
MISSON	115	POTRERO	115	#1	Potrero-Larkin E 115 kV line	105.9%	107.0%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission 115 kV line	93.5%	94.3%
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission 115 kV line	82.2%	83.6%
LARKIN F	115	LARKIN 2	12	#6	Potrero-Larkin D 115 kV line	87.1%	88.6%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission 115 kV line	87.0%	88.5%
LARKIN E	115	LARKIN 2	12	#4	Martin C-Larkin F 115 kV line	84.5%	85.9%
LARKIN F	115	LARKIN 1	12	#5	Potrero-Larkin D 115 kV line	83.9%	85.4%
LARKIN E	115	LARKIN 1	12	#3	Martin C-Larkin F 115 kV line	83.2%	84.6%
LARKIN D	115	LARKIN 2	12	#2	Martin C-Larkin F 115 kV line	82.5%	83.9%

Table 7-9: No generation at Potrero; Embarcadero-Potrero 230 kV Cable added
Trans Bay Cable In; Recabling Project Complete
Category C outages

Facility					Worst Contingency	LOADING	
						2014	2019
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission and Larkin F-Martin 115 kV	174.5%	178.0%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission and Potrero-Larkin D 115 kV	173.3%	177.0%
MISSON	115	POTRERO	115	#1	Potrero-Larkin D and Potrero-Larkin E 115 kV	128.1%	129.6%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission and Potrero-Hunters point 115 kV	107.7%	108.4%
LARKIN F	115	LARKIN 1	12	#5	Larkin E-Mission and Potrero-Larkin D 115 kV	179.4%	183.1%
LARKIN D	115	LARKIN 2	12	#2	Larkin E-Mission and Larkin F-Martin 115 kV	179.0%	182.5%
LARKIN E	115	LARKIN 1	12	#3	Potrero-Larkin D and Larkin F-Martin 115 kV	178.5%	182.0%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D and Larkin F-Martin 115 kV	178.0%	181.5%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission and Larkin F-Martin 115 kV	178.0%	181.5%
LARKIN F	115	LARKIN 2	12	#6	Larkin E-Mission and Potrero-Larkin D 115 kV	176.8%	180.2%

7.3.4 Conclusions

- Provided the Trans Bay Cable is proven to be reliable and the recabling of the Martin – Bayshore – Potrero lines 1 and 2 are completed in 2010, Potrero Units 3, 4, 5, and 6 can be released from their RMR agreements for 2011 and beyond;
- Provided the Trans Bay Cable is proven to be reliable and the recabling of the Martin – Bayshore – Potrero lines 1 and 2 are complete, a new Embarcadero – Potrero 230kV cable is not needed over the 10-year planning horizon;
- A DC runback scheme for the Trans Bay Cable will be required to address an overload of the Mission-Potrero 115kV cable for the loss of the Potrero-Larken E 115kV cable. A runback scheme has been installed as part of the Trans Bay Cable Project;
- Some 115 kV cables and 115/12 kV transformers are found overloaded under Category C contingency conditions for which mitigation plans will be finalized with PG&E before the summer of 2010;
- Voltages in San Francisco remain within the allowable NERC/WECC criteria for all Category B and Category C contingencies through 2019;
- If both existing Martin-Embarcadero 230 kV cables trip, about 95% of the Embarcadero load (260 MW) will automatically drop. This entire load can be restored by bringing at least one cable back in service.

ATTACHMENT V

Table 3-3.4.6: Summary of thermal overloads for summer peak conditions – Central Valley

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading %		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
CVLY-T-005	Placer 115/60 kV	N/A	A	Normal	93%	106%	2017	Upgrade Atlantic-Placer corridor to 115 kV operation
CVLY-T-041	Madison-Vaca 115 kV	N/A	A	Normal	100.1%	105.4%	2014	Reconductor
CVLY-T-057	Tesla-Weber 230 kV	N/A	A	Normal	<100%	108%	2016	Reconductor
CVLY-T-060	Hammer-Country Club 60 kV	N/A	A	Normal	<100%	115%	2015	Mosher area reinforcement
CVLY-T-066	Stagg-Hammer 60 kV	N/A	A	Normal	<100%	104%	2018	Mosher area reinforcement plus Hammer area reinforcement
CVLY-T-079	Tesla-Kasson-Manteca 115 kV	N/A	A	Normal	<100%	115%	2015	Tesla-Bellota 115 kV area reinforcement
CVLY-T-087	Stockton A-Weber #1 60 kV	N/A	A	Normal	<100%	103%	2018	Reconductor
CVLY-T-005	Placer 115/60 kV	Halsey #1	B	L-1	93%	104%	2017	Upgrade Atlantic-Placer corridor to 115 kV operation
CVLY-T-006	Drum-Bell 115 kV	Gold Hill-Placer #1 115 kV and Chicago Park #1	B	L-1/G-1	99%	103%	2016	
CVLY-T-008	Rio Oso-Atlantic 230 kV	Rio Oso-Gold Hill 115 kV and Ralston # 1	B	L-1/G-1	<100%	100%	2020	Loop Rio Oso-Gold Hill 230 kV into Atlantic and reconductor form Rio Oso to Atlantic
CVLY-T-012	Pease-Rio Oso 115 kV	Table Mt-Rio Oso 230 kV and Ralston # 1	B	L-1/G-1	<100%	100%	2020	Reconductor
					<100%	104%	2017	
					<100%	104%	2017	
CVLY-T-016	Drum-Grass Valley-Weimar 60 kV	Colgate-Grass Valley 60 kV and Rollins #1	B	L-1/G-1	103%	113%	2013	Reconductor and/or disable automatics at Grass Valley and Change configuration at Weimar
					110%	121%	2010	
					115%	126%	2010	
CVLY-T-036	Woodland-Davis 115 kV	Rio Oso-Brighton 230 kV and UC Davis #1	B	L-1/G-1	101.3%	111.4%	2013	Woodland-Davis-West Sacramento Long-Term
		Rio Oso-Brighton 230 kV	B	L-1	100.2%	110.2%	2014	

TPL 003: System Performance Following Loss of Two or More BES Elements

- There are 64 facilities with identified thermal overloads, 28 facilities with identified low voltage and 20 facilities with voltage deviation concerns under the Category C performance requirement. Also, 14 Category C contingencies were found to result in the power flow case divergence.

Tables 3-3.4.6 to 3-3.4.9 document the worst thermal overloads and voltage concerns identified for the summer peak conditions along with ISO-proposed solutions.

Table 3-3.4.6: Summary of thermal overloads for summer peak conditions – Central Valley (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading % 2014	Loading % 2019	Exp. Yr. of Occurrence	ISO Proposed Solution
CVLY-T-082	Tesla-Tracy 115 kV	Schulte-Lammers 115 kV and Stanislaus #1	B	L-1/G-1	107%	119%	2011	Tesla-Bellota 115 kV area reinforcement
					105%	117%	2012	
					100%	112%	2014	
CVLY-T-086	Weber 60 kV Bus Tie	Weber #2 230/60 kV	B	T-1	109%	117%	2010	Replace Bus Tie
CVLY-T-087	Stockton A-Weber #1 60 kV	Stockton A-Weber #2 60 kV and Stockton Wastewater #1	B	L-1/G-1	107%	113%	2010	Reconductor
		Stockton A-Weber #2 60 kV	B	L-1	105%	112%	2010	
CVLY-T-088	Stockton A-Weber #2 60 kV	Stockton A-Weber #1 60 kV and Stockton Wastewater #1	B	L-1/G-1	<100%	100%	2020	Reconductor
CVLY-T-001		Gold Hill 115 kV Bus Section 2	C	Bus	N/A	Diverge	2019	Upgrade to BAAH
CVLY-T-002		Gold Hill #1 and #2 230/115 kV	C	T-1-1	Diverge	Diverge	2010	Gold Hill #3 230/115 kV
CVLY-T-003	Gold Hill # 1 230/115 kV	Higgins-Bell 115 kV and Gold Hill # 2 230/115 kV	C	L-1/T-1	107%	117%	2010	
CVLY-T-004	Gold Hill # 2 230/115 kV	Higgins-Bell 115 kV and Gold Hill # 1 230/115 kV	C	L-1/T-1	107%	117%	2010	
CVLY-T-006	Drum-Bell 115 kV	Gold Hill 230 kV Bus Section 2	C	Bus	102%	109%	2013	Upgrade Atlantic-Placer corridor to 115 kV operation
		Gold Hill-Placer #1 and #2 115 kV	C	L-1-1	121%	144%	2010	
		DCTL Gold Hill-Placer #1 and #2 115kV	C	DCTL	121%	144%	2010	
		Gold Hill-Placer #1 and #2 115 kV	C	L-1-1	100%	114%	2014	
		DCTL Gold Hill-Placer #1 and #2 115kV	C	DCTL	100%	114%	2014	
CVLY-T-007	Gold Hill-Placer # 2 115 kV	Gold Hill-Placer # 1 115 kV and Higgins-Bell 115 kV	C	L-1-1	<100%	105%	2017	

Table 3-3.4.6: Summary of thermal overloads for summer peak conditions – Central Valley (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading % 2014	Loading % 2019	Exp. Yr. of Occurrence	ISO Proposed Solution
CVLY-T-008	Rio Oso-Atlantic 230 kV	Gold Hill 230 kV Bus Section 2	C	Bus	108%	118%	2010	Loop Rio Oso-Gold Hill 230 kV into Atlantic and reconductor form Rio Oso to Atlantic
		Rio Oso-Gold Hill 115 kV and Rio Oso-Lincoln 115 kV	C	L-1-1	107%	117%	2010	
CVLY-T-009	Rio Oso-Gold Hill 230 kV	Rio Oso-Atlantic 230 kV and Rio Oso-Lincoln 115 kV	C	L-1-1	<100%	105%	2017	
CVLY-T-010	Gold Hill-Missouri Flat # 1 115 kV	Gold Hill-Clarksville 115 kV and Gold Hill-Missouri Flat # 2 115 kV	C	L-1-1	127%	143%	2010	Clarksville area reinforcement
CVLY-T-011	Palermo-Pease 115 kV	Colgate-Rio Oso 230 kV and Palermo-East Nicolaus 115 kV	C	L-1-1	<100%	102%	2019	Reconductor
		Table Mt-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C	L-1-1	<100%	103%	2018	
		Colgate-Rio Oso 230 kV and Palermo-East Nicolaus 115 kV	C	L-1-1	<100%	102%	2019	
		Table Mt-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C	L-1-1	<100%	103%	2018	
CVLY-T-012	Pease-Rio Oso 115 kV	Rio Oso 230 kV Bus Section 1	C	Bus	102%	112%	2013	Reconductor
		Table Mt-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C	L-1-1	119%	133%	2010	
		DCTL Colgate-Rio Oso 230 kV and Table Mt-Rio Oso 230 kV	C	DCTL	119%	133%	2010	
		Rio Oso 230 kV Bus Section 1	C	Bus	107%	118%	2011	

Table 3-3.4.8: Summary of low voltages for summer peak conditions – Central Valley

ID	Substation	Worst Contingency	Category	Category Description	Min Post-Cont Voltage (PU)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
CVLY-V-001	Gold Hill 230 kV	N/A	A	Normal	>0.95	0.93	2018	Rio Oso/Gold Hill area Voltage Support
CVLY-V-002	Rio Oso 230 kV	N/A	A	Normal	>0.95	0.93	2018	
CVLY-V-003	Atlantic 230 kV	N/A	A	Normal	0.95	0.92	2017	
CVLY-V-004	Ralston 230 kV	N/A	A	Normal	>0.95	0.94	2019	
CVLY-V-005	Middle Fork 230 kV	N/A	A	Normal	>0.95	0.95	2019	
CVLY-V-006	Rocklin 60 kV	N/A	A	Normal	>0.95	0.94	2019	Upgrade Atlantic-Placer corridor to 115 kV operation
CVLY-V-007	Atlantic 60 kV	N/A	A	Normal	>0.95	0.94	2019	
CVLY-V-008	Del Mar 60 kV	N/A	A	Normal	>0.95	0.93	2018	
CVLY-V-009	Taylor 60 kV	N/A	A	Normal	>0.95	0.94	2019	
CVLY-V-013	Sierra Pine 60 kV	N/A	A	Normal	>0.95	0.93	2018	
CVLY-V-018	Plainfield 60 kV	N/A	A	Normal	0.94	0.92	2014	Reconductor 7 miles and/or voltage support
CVLY-V-019	Brighton 230 kV	N/A	A	Normal	0.94	0.92	2014	Woodland-Davis-West Sacramento Long-Term
CVLY-V-034	Lockeford 230 kV	N/A	A	Normal	>0.95	0.94	2019	Industrial area reinforcement
CVLY-V-039	Westley 60 kV	N/A	A	Normal	0.93	0.91	2012	Reconductor 12 miles or voltage support
CVLY-V-014	Apple Hill 115 kV	Gold Hill-Missouri Flat #2 115 kV and El Dorado #1	B	L-1/G-1	>0.92	0.9	2018	Clarksville area reinforcement
CVLY-V-016	Forest Hill 60 kV	Colgate-Grass Valley 60 kV and Oxbow #1	B	L-1/G-1	>0.92	0.9	2018	Reconductor and/or disable automatics at Grass Valley and Change configuration at Weimar

Table 3-3.4.8: Summary of low voltages for summer peak conditions – Central Valley (cont'd)

ID	Substation	Worst Contingency	Category	Category Description	Min Post-Cont Voltage (PU)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
CVLY-V-027	Dunningan 60 kV	Cortina # 1 60 kV	B	L-1	0.89	0.88	2010	Change/Disable automatics or reconductor
CVLY-V-032	Lammers 115 kV	Schulte-Lammers 115 kV and Stanislaus #1	B	L-1/G-1	>0.92	0.9	2018	Loop Tesla-Kasson-Manteca 115 kV into Lammers and/or Voltage Support
		Schulte-Lammers 115 kV	B	L-1	>0.92	0.91	2019	
CVLY-V-033	Linden 60 kV	Weber #1 230/60 kV	B	T-1	0.91	0.88	2012	Linden area reinforcement
		Weber-Mormon Jct 60 kV	B	L-1	>0.92	0.91	2019	
CVLY-V-034	Lockeford 230 kV	Lockeford-Bellota 230 kV and Lodi CT #1	B	L-1/G-1	0.83	0.79	2010	Industrial area reinforcement
		Lockeford-Bellota 230 kV	B	L-1	0.87	0.84	2010	
CVLY-V-036	Industrial 60 kV	Lockeford-Bellota 230 kV and Lodi CT #1	B	L-1/G-1	0.9	0.84	2012	
CVLY-V-037	Mosher 60 kV	Country Club-Hammer 60 kV	B	L-1	0.9	0.88	2010	Mosher area reinforcement
CVLY-V-038	Stagg 230 kV	Stagg #4 230/60 kV	B	T-1	>0.92	0.89	2017	Stagg 230 kV area reinforcement
CVLY-V-039	Westley 60 kV	Manteca #3 115/60 kV	B	T-1	0.88	0.87	2010	Kasson-Manteca 60 kV system rearrangement
CVLY-V-010	Newcastle 115 kV	Gold Hill-Placer # 2 115 kV and Drum-Bell 115 kV	C	L-1-1	>0.92	0.9	2018	Upgrade Atlantic-Placer corridor to 115 kV operation
CVLY-V-011	Flint 115 kV	Gold Hill-Placer # 1 115 kV and Drum-Bell 115 kV	C	L-1-1	>0.92	0.87	2015	
CVLY-V-012	Placer 115 kV	Gold Hill-Placer #1 and #2 115 kV	C	L-1-1	0.91	0.86	2013	
		DCTL Gold Hill-Placer #1 and #2 115kV	C	DCTL	0.91	0.86	2013	
CVLY-V-013	Sierra Pine 60 kV	Rio Oso-Atlantic 230 kV and Atlantic-Gold Hill 230 kV	C	L-1-1	0.8	0.73	2010	Loop Rio Oso-Gold Hill 230 kV into Atlantic

Table 3-3.4.8: Summary of low voltages for summer peak conditions – Central Valley (cont'd)

ID	Substation	Worst Contingency	Category	Category Description	Min Post-Cont Voltage (PU)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
CVLY-V-034	Lockeford 230 kV	Brighton-Bellota 230 kV and Lockeford-Bellota 230 kV	C	L-1-1	0.86	0.81	2010	Industrial area reinforcement
		Lockeford-Bellota 230 kV and Brighton-Bellota 230 kV	C	DCTL	0.86	0.81	2010	
CVLY-V-035	Lodi 60 kV	Lockeford-Bellota 230 kV and Lockeford #2 230/60 kV	C	L-1/T-1	>0.92	0.88	2016	
CVLY-V-036	Industrial 60 kV	Lockeford-Bellota 230 kV and Lockeford-Industrial 60 kV	C	L-1-1	>0.92	0.88	2016	
		Lockeford-Bellota 230 kV and Brighton-Bellota 230 kV	C	DCTL	>0.92	0.89	2017	
CVLY-V-037	Mosher 60 kV	Lockeford-Bellota 230 kV and Country Club-Hammer 60 kV	C	L-1-1	0.78	Div.	2010	Mosher area reinforcement
CVLY-V-038	Stagg 230 kV	Stagg-Tesla 230 kV and Eight Mile-Tesla 230 kV	C	L-1-1	0.78	Div.	2010	Stagg 230 kV area reinforcement
CVLY-V-039	Westley 60 kV	Tracy-Tesla 115 kV and Schulte-Lammers 115 kV	C	L-1-1	0.87	0.81	2010	Kasson-Manteca 60 kV system rearrangement

Table 3-3.4.9: Summary of voltage deviations for summer peak conditions – Central Valley

ID	Substation	Worst Contingency	Category	Category Description	Post Cont Voltage Deviation (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
CVLY-V-045	Wilkins 60 kV	Cortina #1 60 kV	B	L-1	10.34	10.93	2010	Change/Disable automatics or reconductor
CVLY-V-051	Lammers 115 kV	Schulte-Lammers 115 kV	B	L-1	<5	8.15	2016	Loop Tesla-Kasson-Manteca 115 kV into Lammers and/or Voltage Support
CVLY-V-052	Linden 60 kV	Weber #1 230/60 kV	B	T-1	5.92	8.69	2012	Linden area reinforcement
CVLY-V-053	Lockeford 230 kV	Lockeford-Bellota 230 kV and Lodi CT #1	B	L-1/G-1	13.52	16.22	2010	Industrial area reinforcement
		Lockeford-Bellota 230 kV	B	L-1	9.35	11.13	2010	
CVLY-V-054	Mondavi 60 kV	Lockeford-Bellota 230 kV and Lodi CT #1	B	L-1/G-1	10.77	15.9	2010	
CVLY-V-056	Mosher 60 kV	Country Club-Hammer 60 kV	B	L-1	9.61	11.22	2010	Mosher area reinforcement
CVLY-V-058	Stagg 230 kV	Stagg-Tesla 230 kV	B	L-1	<5	5.39	2019	Stagg 230 kV area reinforcement
CVLY-V-061	Westley 60 kV	Manteca #3 115/60 kV	B	T-1	5.38	5.3	2013	Kasson-Manteca 60 kV system rearrangement
CVLY-V-040	Bell 115 kV	Gold Hill-Placer # 1 115 kV and Drum-Bell 115 kV	C	L-1-1	6.91	10.62	2018	Upgrade Atlantic-Placer corridor to 115 kV operation
CVLY-V-041	Penryn 60 kV	Gold Hill-Placer # 1 and # 2 115 kV	C	L-1-1	<10	10.86	2018	
		DCTL Gold Hill-Placer # 1 and # 2 115 kV	C	DCTL	<10	10.86	2018	
CVLY-V-042	Shingle Springs 115 kV	Gold Hill 115 kV Bus Section 2	C	Bus	31.41	Div.	2010	Upgrade to BAAH
CVLY-V-043	Sierra Pine 60 kV	Rio Oso-Atlantic 230 kV and Atlantic-Gold Hill 230 kV	C	L-1-1	16.75	21.7	2010	Loop Rio Oso-Gold Hill 230 kV into Atlantic
CVLY-V-044	Cortina 230 kV	CPV-Cortina 230 kV and Cortina-Vaca 230 kV	C	L-1-1	13.8	Div.	2011	Loop into Cortina another 230 kV line

ATTACHMENT W

Summary of identified thermal violations and proposed mitigation

Study Area: Fresno - summer peak conditions

Thermal Overloads

ID	Overloaded Facility Name	Worst Contingency(ies)	Category	Loading (%)		ISO Proposed Solution
				2014	2019	
FRES-SP-T-001	Bank between Los Banos 230 kV To Los Banos 70 kV Ckt #3	Los Banos 230/70 kV Bank #4	B	113%	126%	Replace with higher capacity trf
FRES-SP-T-002	Bank between Los Banos 230 kV To Los Banos 70 kV Ckt #3	Los banos 230/70 kV Bank #4 and Dfs Tp - Oro Loma 115 kV #2	C3	151%	162%	Replace with 200 MVA trf
FRES-SP-T-003	Bank between Los Banos 230 kV To Los Banos 70 kV Ckt #3	Hammons - Panoche 115 kV #1 and Los Banos 230/70 kV Bank # 4	C3	144%	158%	Replace with 200 MVA trf
FRES-SP-T-004	Bank between Los Banos 230 kV To Los Banos 70 kV Ckt #3	Los Banos 230/70 kV #4 and Mendota 115/70 kV #1	C3	129%	141%	Replace with 200 MVA trf
FRES-SP-T-005	Bank between Herndon 230 kV To Herndon 115 kV Ckt #1	Herndon 230/115 kV Bank #2 and Herndon 230/15 kV Bank #3	C3	109%	116%	Load shedding plan
FRES-SP-T-006	Bank between Herndon 230 kV To Herndon 115 kV Ckt #2	Herndon 230/115 kV Bank #1 and Herndon 230/15 kV Bank #3	C3	109%	117%	Load shedding plan
FRES-SP-T-007	Bank between Herndon 230 kV To Herndon 115 kV Ckt #3	Herndon 230/115 kV Bank #1 and Herndon 230/115 kV Bank #2	C3	109%	117%	Load shedding plan
FRES-SP-T-008	Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #1	McCall 230/115 kV Bank #2 and McCall 230/115 kV Bank #3	C3	106%	118%	Load shedding plan
FRES-SP-T-009	Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #2	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #3	C3	104%	116%	Load shedding plan
FRES-SP-T-010	Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #3	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #2	C3	106%	118%	Load shedding plan
FRES-SP-T-011	Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #1	McCall 230/115 kV Bank #2 and McCall 230/115 kV Bank #3	C3	105%	117%	Load shedding plan
FRES-SP-T-012	Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #2	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #3	C3	100%	112%	Load shedding plan
FRES-SP-T-013	Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #3	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #2	C3	105%	116%	Load shedding plan
FRES-SP-T-014	Bank between Herndon 115 kV To Herndon 115 kV Ckt #1	Herndon 230/115 kV Bank #2 and Herndon 230/15 kV Bank #3	C3	108%	115%	Load shedding plan
FRES-SP-T-015	Bank between Herndon 115 kV To Herndon 115 kV Ckt #2	Herndon 230/115 kV Bank #1 and Herndon 230/15 kV Bank #3	C3	108%	116%	Load shedding plan
FRES-SP-T-016	Bank between Corcoran 115 kV To Corcoran 70 kV Ckt #2	N/A	A	105%	110%	add 2nd bank
FRES-SP-T-017	Bank between Corcoran 115 kV To Corcoran 70 kV Ckt #2	Kingsburg - Corcoran 115 kV #1 and Kingsburg - Corcoran 115 kV #2	C3	102%	110%	add 2nd bank
FRES-SP-T-018	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Helms - Gregg 230 kV #1 and #2	C5	108%	121%	reconductor
FRES-SP-T-020	Line between Gregg 230 kV To Herndon 230 kV Ckt #1	Gregg - Herndon 230 kV #1	B	111%	117%	upgrade terminal equipment
FRES-SP-T-021	Line between Gregg 230 kV To Herndon 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and Gregg - Ashlan 230 kV #1 1 (Drop Helm 3)	C3	150%	159%	upgrade terminal equipment
FRES-SP-T-022	Line between Gregg 230 kV To Herndon 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and Panoche - Kearney 230 kV #1	C3	135%	147%	upgrade terminal equipment
FRES-SP-T-023	Line between Gregg 230 kV To Herndon 230 kV Ckt #1	Panoche - Kearney 230 kV #1 and Gregg - Herndon 230 kV #2 (Drop Helm 3)	C3	135%	147%	upgrade terminal equipment
FRES-SP-T-025	Line between Gregg 230 kV To Herndon 230 kV Ckt #2	Gregg - Herndon 230 kV #1	B	111%	117%	upgrade terminal equipment
FRES-SP-T-026	Line between Gregg 230 kV To Herndon 230 kV Ckt #2	Gregg - Herndon 230 kV #1 and Gregg - Ashlan 230 kV #1 1 (Drop Helm 3)	C3	150%	159%	upgrade terminal equipment
FRES-SP-T-027	Line between Gregg 230 kV To Herndon 230 kV Ckt #2	Gregg - Herndon 230 kV #1 and Panoche - Kearney 230 kV #1	C3	135%	147%	upgrade terminal equipment

FRES-SP-T-028	Line between Gregg 230 kV To Herndon 230 kV Ckt #2	Panoche - Kearney 230 kV #1 and Gregg - Herndon 230 kV #1 (Drop Helm 3)	C3	135%	147%	upgrade terminal equipment
FRES-SP-T-030	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Herndon - Ashlan 230 kV #1	B	<100%	105%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-031	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and Gregg - Herndon 230 kV #2 (Drop Helm 3)	C3	141%	151%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-032	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Gregg - Helms PP 230 kV #2 and Herndon - Ashlan 230 kV #1	C3	99%	107%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-033	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Herndon - Ashlan 230 kV #1 and Panoche - Kearney 230 kV #1	C3	99%	106%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-034	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Panoche - Kearney 230 kV #1 and Herndon - Ashlan 230 kV #1	C3	99%	106%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-035	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Gregg - Gates 230 kV #1 and Herndon - Ashlan 230 kV #1	C3	99%	106%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-036	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Herndon-Kearney and Herndon-Ashlan	C5	<100%	105%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-037	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and #2	C5	180%	191%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-038	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gregg - Ashlan 230 kV #1 1 (Drop Helm 3)	B	<100%	105%	Reconductor Herndon-Ashlan
FRES-SP-T-039	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gregg - Helms PP 230 kV #2 and Gregg - Ashlan 230 kV #1 1 (Drop Helm 3)	C3	99%	107%	Reconductor Herndon-Ashlan
FRES-SP-T-040	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gregg - Ashlan 230 kV #1 1 (Drop Helm 3) and Panoche - Kearney 230 kV #1	C3	99%	106%	Reconductor Herndon-Ashlan
FRES-SP-T-041	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Panoche - Kearney 230 kV #1 and Gregg - Ashlan 230 kV #1 1 (Drop Helm 3)	C3	99%	106%	Reconductor Herndon-Ashlan
FRES-SP-T-042	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gregg - Ashlan 230 kV #1 1 (Drop Helm 3) and Gates - Gregg 230 kV #1 230 + trip helms unit3	C3	99%	106%	Reconductor Herndon-Ashlan
FRES-SP-T-044	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gates - Gregg 230 kV #1 and Gregg - Ashlan 230 kV #1	C5	99%	106%	Reconductor Herndon-Ashlan
FRES-SP-T-045	Line between Fgrdn T1 230 kV To Ashlan 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and #2	C5	104%	109%	Reconductor Herndon-Ashlan
FRES-SP-T-046	Line between Fgrdn T2 230 kV To Ashlan 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and Gregg - Herndon 230 kV #2 (Drop Helm 3)	C3	112%	120%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-047	Line between Fgrdn T2 230 kV To Ashlan 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and #2	C5	152%	161%	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-048	Line between Chwchlla 115 kV To Certan T 115 kV Ckt #1	Woodward - Chldhosp 115 kV #1 and Kerckhof Unit 1	B	<100%	101%	Load shedding plan
FRES-SP-T-049	Line between Chwchlla 115 kV To Certan T 115 kV Ckt #1	Woodward - Chldhosp 115 kV #1 and Kerchoff 115/13 kV Bank #1	C3	<100%	101%	Load shedding plan
FRES-SP-T-050	Line between Certan T 115 kV To Le Grand 115 kV Ckt #1	Clovis J1 - Sanger 115 kV #1 and Kerckhf2 - Sanger 115 kV #1	C3	121%	111%	raise kerchoff gen or shed load
FRES-SP-T-051	Line between Certan T 115 kV To Le Grand 115 kV Ckt #1	Kerckhoff - Clovis - Sanger 115 kV #1 and #2	C5	121%	111%	short-term rating and then shed load
FRES-SP-T-053	Line between Atwater 115 kV To Wilson A 115 kV Ckt #1	Atwater - Merced 115 kV #1 and Wilson B - El Captn 115 kV #1	C3	105%	116%	verify operating procedures
FRES-SP-T-058	Line between Exchequr 115 kV To Le Grand 115 kV Ckt #1	Exchequr - Saxoncrk 70 kV #1 and Merced 115/70 kV Bank #2	C3	110%	107%	reduce exchequer, merced falls, mcswain
FRES-SP-T-059	Line between Le Grand 115 kV To Wilson A 115 kV Ckt #1	Clovis J1 - Sanger 115 kV #1 and Kerckhf2 - Sanger 115 kV #1	C3	113%	112%	Reconductor or SPS
FRES-SP-T-060	Line between Le Grand 115 kV To Wilson A 115 kV Ckt #1	Kerckhoff - Clovis - Sanger 115 kV #1 and #2	C5	113%	112%	Reconductor or SPS
FRES-SP-T-061	Line between Corsgold 115 kV To Oakh_Jct 115 kV Ckt #1	N/A	A	<100%	110%	reconductor
FRES-SP-T-062	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson - Atwater 115 kV #1 and Wilson A - Wilson B 115 kV #1	C3	<100%	107%	verify operating procedures
FRES-SP-T-063	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson B - Merced 115 kV #2 and Merced 115/70 kV Bank #2	C3	<100%	102%	verify operating procedures
FRES-SP-T-065	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson A - Wilson B 115 kV #1 and Wilson 230kV/Wilson B 115 kV Bank #2	C3	112%	122%	verify operating procedures
FRES-SP-T-066	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson B - El Captn 115 kV #1 and Wilson B - Merced 115 kV #2	C3	112%	125%	verify operating procedures
FRES-SP-T-067	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Atwater - Cresey T 115 kV #1 and Wilson B - Merced 115 kV #2	C3	101%	113%	verify operating procedures

FRES-SP-T-068	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson - Atwater 115 kV #1 and Wilson B - Merced 115 kV #2	C3	101%	113%	verify operating procedures
FRES-SP-T-069	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson-Atwater and El Capitan-Wilson	C5	131%	147%	SPS
FRES-SP-T-071	Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson A - Merced 115 kV #1 and Wilson B - El Captn 115 kV #1	C3	110%	122%	verify operating procedures
FRES-SP-T-072	Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Atwater - Cresey T 115 kV #1 and Wilson A - Merced 115 kV #1	C3	101%	113%	verify operating procedures
FRES-SP-T-073	Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson - Atwater 115 kV #1 and Wilson A - Merced 115 kV #1	C3	99%	111%	verify operating procedures
FRES-SP-T-074	Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson-Atwater and El Capitan-Wilson	C5	118%	133%	verify operating procedures
FRES-SP-T-075	Line between Oro Loma 70 kV To Poso J1 70 kV Ckt #1	Mendota 115/70 kV #1	B	104%	105%	reconductor
FRES-SP-T-076	Line between Oro Loma 70 kV To Poso J1 70 kV Ckt #1	Mendota - Dairyland 115 kV #1 and Panoche - Mendota 115 kV #1 (Drop DG Pan1 Unit 1)	C3	107%	110%	verify operating procedures
FRES-SP-T-077	Line between Oro Loma 70 kV To Poso J1 70 kV Ckt #1	Mendota 115/70 kV #1 and Dfs Tp - Oro Loma 115 kV #2	C3	122%	123%	reconductor
FRES-SP-T-078	Line between Oro Loma 70 kV To Poso J1 70 kV Ckt #1	Hammons - Panoche 115 kV #1 and Mendota 115/70 kV #1	C3	110%	113%	reconductor
FRES-SP-T-079	Line between Merced 70 kV To El Nido Tp 70 kV Ckt #1	Merced 115/70 kV Bank #2 and Mariposa - Exchequr 70 kV #1	C3	102%	102%	verify operating procedures
FRES-SP-T-080	Line between Merced 70 kV To El Nido Tp 70 kV Ckt #1	Mc Swain - Mrcdflls 70 kV #1 (Drop McSwain Unit 1) and Merced 115/70 kV Bank #2	C3	101%	101%	verify operating procedures
FRES-SP-T-081	Line between Merced 70 kV To El Nido Tp 70 kV Ckt #1	Merced - Mrccdflls 70 kV #1 and Merced 115/70 kV Bank #2	C3	101%	101%	verify operating procedures
FRES-SP-T-082	Line between Ortiga 70 kV To Mrcysprs 70 kV Ckt #1	Livngstn - Los Banos 70 kV #1 and Canal - Santa Rta 70 kv #1	C3	<100%	102%	verify operating procedures
FRES-SP-T-083	Line between Ortiga 70 kV To Mrcysprs 70 kV Ckt #1	Oro Loma - Dos Pals 70 kV #1 and Livngstn - Los Banos 70 kV #1	C3	103%	115%	verify operating procedures
FRES-SP-T-084	Line between Exchequr 70 kV To Bervlly 70 kV Ckt #1	Mariposa - Exchequr 70 kV #1	B	<100%	108%	reconductor and voltage support
FRES-SP-T-087	Line between Exchequr 70 kV To Mcswainj 70 kV Ckt #1	Borden-Gregg (Drop Helms Unit 3) and Exchequr - Le Grand 115 kV #1 (Drop 34306 Unit 1)	C3	119%	157%	reconductor and voltage support
FRES-SP-T-091	Line between Borden 70 kV To Cassidy 70 kV Ckt #1	Mc Call - Wahtoke 115 kV #1 and Frantdm GSU	C3	<100%	105%	increase wishon gen or Load shedding
FRES-SP-T-092	Line between Borden 70 kV To Cassidy 70 kV Ckt #1	Frantdm GSU and Tvy Vlly - Reedley 70 kV #1	C3	<100%	107%	increase wishon gen or Load shedding
FRES-SP-T-095	Line between Tomatak 70 kV To Mendota 70 kV Ckt #1	Livngstn - Los Banos 70 kV #1 and Dfs Tp - Oro Loma 115 kV #2	C3	<100%	102%	Load shedding plan
FRES-SP-T-096	Line between Sanger 115 kV To Cal Ave 115 kV Ckt #1	Mc Call - Danishcm 115 kV #1 and Wst Frso - Mc Call 115 kV #1	C3	108%	115%	Short-term rating
FRES-SP-T-097	Line between Sanger 115 kV To Cal Ave 115 kV Ckt #1	McCall-West Fresno & Mc Call - California	C5	108%	115%	Short-term rating
FRES-SP-T-098	Line between Mc Call 115 kV To Danishcm 115 kV Ckt #1	Cal Ave - Sanger 115 kV #1 and Wst Frso - Mc Call 115 kV #1	C3	116%	129%	verify operating procedures
FRES-SP-T-099	Line between Mc Call 115 kV To Wst Frno 115 kV Ckt #1	Mc Call - Danishcm 115 kV #1 and Cal Ave - Sanger 115 kV #1	C3	103%	111%	Short-term rating
FRES-SP-T-100	Line between Mc Call 115 kV To Gaurd J1 115 kV Ckt #1	KcognJct - Kingsbrg 115 kV #1 (Drop Kingsburg Unit 1) and Kingsburg - Gwf Hep 115 kV #1	C3	108%	118%	verify operating procedures
FRES-SP-T-101	Line between Reedley 115 kV To Piedra_1 115 kV Ckt #1	SngrJct - Reedley 115 kV #1 (Drop Sangerco Unit 1) and Mc Call - Wahtoke 115 kV #1	C3	128%	146%	verify operating procedures
FRES-SP-T-102	Line between Kings_J1 115 kV To Kings J2 115 kV Ckt #1	Mc Call - Gaurd J2 115 kV #1 and Kingsburg - Gwf Hep 115 kV #1	C3	122%	134%	verify operating procedures
FRES-SP-T-103	Line between Danishcm 115 kV To Cal Ave 115 kV Ckt #1	Cal Ave - Sanger 115 kV #1 and Wst Frso - Mc Call 115 kV #1	C3	113%	126%	verify operating procedures
FRES-SP-T-104	Line between Barton115 kV To Herndon 115 kV Ckt #1	Manchester - Herndon 115 kV #1 and Woodward - Chldhosp 115 kV #1	C3	102%	110%	verify operating procedures
FRES-SP-T-105	Line between Manchstr 115 kV To Herndon 115 kV Ckt #1	Barton - Herndon 115 kV #1 and Woodward - Chldhosp 115 kV #1	C3	103%	112%	verify operating procedures
FRES-SP-T-107	Line between Kings J2 115 kV To Kingsburg 115 kV Ckt #1	Mc Call - Gaurd J2 115 kV #1 and Kingsburg - Gwf Hep 115 kV #1	C3	99%	108%	verify operating procedures

FRES-SP-T-108	Line between Kingsburg 115 kV To Gaurd J1 115 kV Ckt #1	KcognJct - Kingsbrg 115 kV #1 (Drop Kingsburg Unit 1) and Kingsburg - Gwf Hep 115 kV #1	C3	123%	135%	verify operating procedures
FRES-SP-T-109	Line between Dnuba_Jt 70 kV To Dinuba 70 kV Ckt #1	Sand Creek - Orsi Jct 70 kV #1	B	<100%	108%	reconductor
FRES-SP-T-110	Line between Dnuba_Jt 70 kV To Dinuba 70 kV Ckt #1	Mc Call - Wahtoke 115 kV #1 and Sand Creek - Orsi Jct 70 kV #1	C3	101%	113%	reconductor
FRES-SP-T-111	Line between Dnuba_Jt 70 kV To Dinuba 70 kV Ckt #1	Wahtoke - Reedley 115 kV #1 and Sand Creek - Orsi Jct 70 kV #1	C3	99%	110%	reconductor
FRES-SP-T-112	Line between Orosi 70 kV To Orsi Jct 70 kV Ckt #1	Reedley - Dinuba 70 kV #1	B	101%	112%	reconductor
FRES-SP-T-113	Line between Orosi 70 kV To Orsi Jct 70 kV Ckt #1	Mc Call - Wahtoke 115 kV #1 and Reedley - Dinuba 70 kV #1 (Drop Dinuba Unit 1)	C3	105%	118%	reconductor
FRES-SP-T-114	Line between Orosi 70 kV To Orsi Jct 70 kV Ckt #1	Wahtoke - Reedley 115 kV #1 and Reedley - Dinuba 70 kV #1 (Drop Dinuba Unit 1)	C3	103%	116%	reconductor
FRES-SP-T-115	Line between Orosi 70 kV To Orsi Jct 70 kV Ckt #1	Reedley - Dinuba 70 kV #1 and Reedley 115/70 kV Bank #2	C3	102%	115%	reconductor
FRES-SP-T-116	Line between Calfax 70 kV To Schlndlr 70 kV Ckt #1	Gats2_tp 70 kV - Colinga2 70 kV #1 and Gates 230115 kB Bank #1	C3	113%	125%	verify operating procedures
FRES-SP-T-117	Line between Templt7 70 kV To Templ_J 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	C3	100%	119%	verify operating procedures
FRES-SP-T-118	Line between Templ_J 70 kV To Psa Rbls 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	C3	100%	119%	verify operating procedures
FRES-SP-T-119	Line between San Migl 70 kV To Psa Rbls 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	C3	117%	152%	verify operating procedures
FRES-SP-T-120	Line between San Migl 70 kV To Psa Rbls 70 kV Ckt #1	Colnga 1 -Jacalito 70 kV #1 and Colnga 2 to Tornado 70 kV #1 (Drop Chv Coal Unit 1)	C3	108%	127%	verify operating procedures
FRES-SP-T-121	Line between Herndon-Barton 115 kV Ckt #1	Helm-McCall and Gates-McCall 230 kV Lines	C5	<95%	105%	develop long-term plan for Mccall 230 system
FRES-SP-T-122	Line between Herndon-Manchester 115 kV Ckt #1	Helm-McCall and Gates-McCall 230 kV Lines	C5	<95%	105%	develop long-term plan for Mccall 230 system
FRES-SP-T-123	Line between Helm-McCall 230 kV Ckt #1	Gates - Gregg 230 kV #1 and Gates-McCall 230 kV Lines	C5	<95%	116%	Reconductor
FRES-SP-T-124	Line between Panoche-Helm 230 kV Ckt #1	Gates - Gregg 230 kV #1 and Gates-McCall 230 kV Lines	C5	<95%	119%	Reconductor

Low Voltages

ID	Substation	Worst Contingency(ies)	Category	Min Post-Cont Voltage (PU)		ISO Proposed Solution
				2014	2019	
FRES-SP-V-001	STOREY 2 230	L-1 Borden - Gregg 230 kV #1(Drop Helm Unit 3)	B	0.92	0.9	review minimum voltage requirements
FRES-SP-V-002	BORDEN 230		B	0.91	0.89	review minimum voltage requirements
FRES-SP-V-003	DINUBA 70	L-1 Reedley - Dinuba 70 kV #1 (Drop Dinuba Unit 1)	B	0.91	0.89	review minimum voltage requirements
FRES-SP-V-016	FIREBAGH 70	Mendota 115/70 kV #1	B	0.9	0.88	review minimum voltage requirements
FRES-SP-V-017	TOMATAK 70	Mendota 115/70 kV #1	B	0.89	0.88	review minimum voltage requirements
FRES-SP-V-018	MENDOTA 70	Mendota 115/70 kV #1	B	0.89	0.88	review minimum voltage requirements
FRES-SP-V-029	STOREY 2 230	L-1 Borden-Gregg 230 kV #1 and L-1 Wilson-Gregg 230 kV #1	C5	0.9	0.88	review minimum voltage requirements
FRES-SP-V-030	BORDEN 230		C5	0.9	0.88	review minimum voltage requirements
FRES-SP-V-031	CORCORAN 115	L-1 McCall-Kingsburg 230 kV #1 and L-1 McCall-Kingsburg 230 kV #2	C5	0.89	0.91	review minimum voltage requirements
FRES-SP-V-032	HRDWK TP 70		C5	0.9	0.87	review minimum voltage requirements
FRES-SP-V-033	HARDWICK 70		C5	0.9	0.88	review minimum voltage requirements
FRES-SP-V-034	HNFRD SW 70		C5	0.9	0.88	review minimum voltage requirements
FRES-SP-V-035	CORCORAN 70		C5	0.9	0.88	review minimum voltage requirements
FRES-SP-V-036	BSWLL TP 70		C5	0.9	0.88	review minimum voltage requirements
FRES-SP-V-037	JGBSWLL 70		C5	0.89	0.87	review minimum voltage requirements
FRES-SP-V-038	ANGIOLA 70		C5	0.89	0.86	review minimum voltage requirements
FRES-SP-V-039	BOSWELL 70		C5	0.9	0.87	review minimum voltage requirements
FRES-SP-V-040	KNGLOBUS 70		C5	0.91	0.89	review minimum voltage requirements

Summary of identified thermal violations and proposed mitigation

Study Area: Fresno - Summer off-peak conditions

Thermal Overloads

ID	Overloaded Facility Name	Worst Contingency(ies)	Category	Loading (%)		ISO Proposed Solution
				2014	Trip 2 Helms Pumps	
FRES-SOP-T-001	Line between Gates 500 kV To Midway 500 kV Ckt #1	N/A	A	100%		
FRES-SOP-T-002	Line between Warnervl 230 kV to Wilson 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C5	101%		Short term rating
FRES-SOP-T-003	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	N/A	A	121%		Reconductor
FRES-SOP-T-004	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	panoche-helm 230 kV line	B	118%		Reconductor
FRES-SOP-T-005	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C5	129%		Reconductor
FRES-SOP-T-006	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Borden-Gregg and Wilson-Gregg	C5	119%		Reconductor
FRES-SOP-T-007	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C5	116%		Reconductor
FRES-SOP-T-008	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Barton-Sanger and Manchester-Sanger	C5	109%		Reconductor
FRES-SOP-T-009	Line between Panoche 230 kV to McMulln1 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C5	152%		Reconductor
FRES-SOP-T-010	Line between Panoche 230 kV to McMulln1 230 kV Ckt 1	Helm-McCall and Gates-McCall	C5	122%		Reconductor
FRES-SOP-T-011	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	N/A	A	111%		Reconductor
FRES-SOP-T-012	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	panoche-helm 230 kV line	B	108%		Reconductor
FRES-SOP-T-013	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C5	119%		Reconductor
FRES-SOP-T-014	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	Borden-Gregg and Wilson-Gregg	C5	109%		Reconductor
FRES-SOP-T-015	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C5	106%		Reconductor
FRES-SOP-T-016	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	Barton-Sanger and Manchester-Sanger	C5	100%		Reconductor
FRES-SOP-T-017	Line between McMulln1 230 kV to Kearney 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C5	141%		Reconductor
FRES-SOP-T-018	Line between McMulln1 230 kV to Kearney 230 kV Ckt 1	Helm-McCall and Gates-McCall	C5	112%		Reconductor
FRES-SOP-T-019	Line between Kearney 230 kV To Herndon 230 kV Ckt #1	N/A	A	100%		Reconductor
FRES-SOP-T-020	Line between Kearney 230 kV To Herndon 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C5	110%		Reconductor
FRES-SOP-T-021	Line between Kearney 230 kV To Herndon 230 kV Ckt #1	Borden-Gregg and Wilson-Gregg	C5	100%		Reconductor
FRES-SOP-T-022	Line between Kearney 230 kV to Herndon 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C5	132%		Reconductor
FRES-SOP-T-023	Line between Kearney 230 kV to Herndon 230 kV Ckt 1	Helm-McCall and Gates-McCall	C5	104%		Reconductor
FRES-SOP-T-024	Line between Panoche 230 kV To Helm 230 kV Ckt #1	gates-mcall 230 kV line trip helms 1 pump	B	103%		Reconductor
FRES-SOP-T-025	Line between Panoche 230 kV to Helm 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C5	160%		Reconductor
FRES-SOP-T-026	Line between Helm 230 kV to MC Call 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C5	155%		Reconductor
FRES-SOP-T-027	Line between Panoche 230 kV to Gates 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C5	118%		Short term rating and terminal equipment upgrade
FRES-SOP-T-028	Line between Panoche 230 kV to Gates 230 kV Ckt 2	Gates-Gregg and Gates-McCall	C5	118%		Short term rating and terminal equipment upgrade
FRES-SOP-T-029	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	N/A	A	118%		Reconductor
FRES-SOP-T-030	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	panoche-helm 230 kV line	B	127%		Reconductor
FRES-SOP-T-031	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Panoche-Kearney and Panoche-Helm	C5	131%		Reconductor
FRES-SOP-T-032	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Panoche-Kearney and Helm-McCall	C5	128%		Reconductor
FRES-SOP-T-033	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Gates-Panoche #1 and #2	C5	115%		Reconductor
FRES-SOP-T-034	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Panoche-Gates #1 and #2	C5	115%		Reconductor
FRES-SOP-T-035	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C5	109%		Reconductor
FRES-SOP-T-036	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C5	106%		Reconductor
FRES-SOP-T-037	Line between Mc Call 230 kV to Hentap2 230 kV Ckt 1	Panoche-Kearney and Gates-Gregg	C5	102%		Reconductor
FRES-SOP-T-038	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C5	108%		Trip 1 pump
FRES-SOP-T-039	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Panoche-Kearney and Panoche-Helm	C5	105%		Trip 2 pumps
FRES-SOP-T-040	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Panoche-Kearney and Helm-McCall	C5	104%		Trip 2 pumps
FRES-SOP-T-041	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Gates-Panoche #1 and #2	C5	103%		Trip 1 pump
FRES-SOP-T-042	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Panoche-Gates #1 and #2	C5	103%		Trip 1 pump
FRES-SOP-T-043	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Borden-Gregg and Wilson-Gregg	C5	102%		Trip 1 pump
FRES-SOP-T-044	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C5	102%		Trip 1 pump

FRES-SOP-T-045	Line between Hentap1 230 kV to Gates 230 kV Ckt 1	Helm-McCall and Gates-McCall	C5	117%		Trip 2 pumps
FRES-SOP-T-046	Line between Hentap2 230 kV To Gates 230 kV Ckt #1	gates-gregg 230 kV line trip helms 1 pump	B	131%	117%	Construct Ring bus at Henrietta and Trip 2 helms pumps
FRES-SOP-T-047	Line between Hentap2 230 kV To Gates 230 kV Ckt #1	panoche-helm 230 kV line	B	103%		Trip 1 helms pump
FRES-SOP-T-048	Line between Hentap2 230 kV To Gates 230 kV Ckt #1	Panoche-Kearney and Panoche-Helm	C5	106%		Trip 2 pumps
FRES-SOP-T-049	Line between Hentap2 230 kV To Gates 230 kV Ckt #1	Panoche-Kearney and Helm-McCall	C5	104%		Trip 2 pumps
FRES-SOP-T-050	Line between Hentap2 230 kV to Gates 230 kV Ckt 1	Panoche-Kearney and Gates-Gregg	C5	133%		Construct Ring bus at Henrietta and Trip 2 helms pumps
FRES-SOP-T-051	Line between Henrieta 230 kV to Henrieta 115 kV Ckt # 3	Helm-McCall and Gates-McCall	C5	113%		Develop 1 hr rating
FRES-SOP-T-052	Line between Gates 230 kV To Midway 230 kV Ckt #1	gates 500/230 kV trf 11 trip helms 1 pump	B	118%	110%	Use Short term rating Trip 2 helms pumps
FRES-SOP-T-053	Line between Arco 230 kV To Midway 230 kV Ckt #1	gates 500/230 kV trf 11 trip helms 1 pump	B	106%	100%	Use Short term rating, Trip 2 helms pumps
FRES-SOP-T-054	Line between Certain T 115kV to Le Grand 115 kV Ckt #1	Helm-McCall and Gates-McCall	C5	108%		Trip 2 pumps
FRES-SOP-T-055	Line between Le Grand 115 kV to Dairyland 115 kV Ckt #1	Gates-Gregg and Gates-McCall	C5	104%		Trip 2 pumps
FRES-SOP-T-056	Line between Oro Loma 115 kV To El Nido 115 kV Ckt #1	Wilson-warnerville 230 kV line melones 1 off	B	110%		Reconductor
FRES-SOP-T-057	Line between Oro Loma 115 kV To El Nido 115 kV Ckt #1	Panoche-Kearney and Panoche-Helm	C5	105%		Reconductor
FRES-SOP-T-058	Line between Oro Loma 115 kV To El Nido 115 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C5	104%		Reconductor
FRES-SOP-T-059	Line between Oro Loma 115 kV To El Nido 115 kV Ckt #1	Panoche-Kearney and Helm-McCall	C5	104%		Reconductor
FRES-SOP-T-060	Line between Oro Loma 115 to EL NIDO 115 1	Gates-Gregg and Gates-McCall	C5	110%		Reconductor
FRES-SOP-T-061	Line between Oro Loma 115 to EL NIDO 115 1	Panoche-Kearney and Gates-Gregg	C5	104%		Reconductor
FRES-SOP-T-062	Line between Sanger 115 kV To Mc Call 115 kV Ckt #3	McCall-Sanger #1 and #2	C5	101%		Develop Short term rating
FRES-SOP-T-063	Line between Contadna 115 kV to Gwf_Hep 115 kV Ckt #1	Helm-McCall and Gates-McCall	C5	104%		Develop Short term rating
FRES-SOP-T-064	Line between Gwf_Hep 115 kV to Lprn Jct 115 kV Ckt #1	Helm-McCall and Gates-McCall	C5	104%		Develop Short term rating
FRES-SOP-T-065	Line between Henrieta 115 to 34519LPRN JCT115 1	Helm-McCall and Gates-McCall	C5	113%		Develop Short term rating

Summary of identified thermal violations and proposed mitigation

Study Area: Kern - Summer peak conditions

Thermal Overloads

ID	Overloaded Facility Name	Worst Contingency(ies)	Category	Loading (%) 2014	Loading (%) 2019	ISO Proposed Solution
KERN-SP-T-001	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3	kern pp 230/115 4 and kern pp 230/115 5	C3	134%	156%	Short-term rating and/or operating procedure
KERN-SP-T-002	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3	30945 "KERN PP" 230 kV Bus Section 1	C1	130%	130%	Short-term rating or SPS
KERN-SP-T-003	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3	kern pp 230/115 4 and kern pp 230/115 5	C3	115%	156%	Short-term rating and/or operating procedure
KERN-SP-T-004	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3	pse-3-kern pwr 115 and kern pwr-kern pp115	C3	104%	108%	Short-term rating and/or operating procedure
KERN-SP-T-005	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3a	kern pp 230/115 4 and kern pp 230/115 5	C3	134%	131%	Short-term rating and/or operating procedure
KERN-SP-T-006	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3a	kern pp 230/115 4 and kern pp 230/115 5	C3	115%	131%	Short-term rating and/or operating procedure
KERN-SP-T-007	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3a	30945 "KERN PP" 230 kV Bus Section 1	C1	111%	111%	Short-term rating or SPS
KERN-SP-T-008	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #4	kern pp 230/115 3 and kern pp 230/115 5	C3	<100%	107%	Short-term rating and/or operating procedure
KERN-SP-T-009	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #4	kern pp 230/115 3a and kern pp 230/115 5	C3	<100%	103%	Short-term rating and/or operating procedure
KERN-SP-T-010	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #4	pse-3-kern pwr 115 and kern pwr-kern pp115	C3	104%	117%	Short-term rating and/or operating procedure
KERN-SP-T-011	Bank between Midway 230 kV To Midway 115 kV Ckt #2a	midway 230/115 and midway 230/115 3	C3	101%	105%	Short-term rating and/or operating procedure
KERN-SP-T-019	Bank between Taft 115 kV To Taft A 70 kV Ckt #2	taft 115/70 and slr-tann g-1	C3	103%	105%	Short-term rating and/or operating procedure
KERN-SP-T-021	Bank between San Luis Obispo 115 kV To San Luis Obispo 70 kV Ckt #3	30905 "TEMPLETN"	C1	104%	104%	Short-term rating and/or operating procedure
KERN-SP-T-022	Line between Stckdl Jt 2 230 kV To Midway 230 kV Ckt #1	Midway-Kern #1 and #4 230 kV line outage	C5	101%	118%	Short-term rating and/or operating procedure
KERN-SP-T-023	Line between Stckdl Jt 2 230 kV To Midway 230 kV Ckt #1	midway-kernpp 230 1 and midway-kernpp 230 2	C3	101%	118%	Short-term rating and/or operating procedure
KERN-SP-T-024	Line between Semitrpc 115 kV To Midway 115 kV Ckt #1	midway-smyrna 115 and famoso-cawelo 115	C3	124%	127%	Short-term rating and/or operating procedure
KERN-SP-T-025	Line between Semitrpc 115 kV To Midway 115 kV Ckt #1	34774 "MIDWAY"115 kV Bus Section 1E	C1	111%	111%	Short-term rating or SPS
KERN-SP-T-026	Line between Westpark 115 kV To Kern Pwr 115 kV Ckt #1	westpark-kern pwr 115 2 and kern pwr-magunden 115	C3	<100%	103%	Short-term rating and/or operating procedure
KERN-SP-T-027	Line between Westpark 115 kV To Kern Pwr 115 kV Ckt #2	westpark-kern pwr 115 1 and kern pwr-magunden 115	C3	<100%	103%	Short-term rating and/or operating procedure
KERN-SP-T-030	Line between Kern Oil Jct 115 kV To Magunden 115 kV Ckt #1	Kern-Westpark #1 and #2	C5	<100%	105%	Short-term rating and/or operating procedure
KERN-SP-T-031	Line between Kern Oil Jct 115 kV To Magunden 115 kV Ckt #1	westpark-kern pwr 115 1 and westpark-kern pwr 115 2	C3	<100%	105%	Short-term rating and/or operating procedure
KERN-SP-T-032	Line between Ganso 115 kV To Midway 115 kV Ckt #1	midway-semitrpc 115 and famoso-cawelo 115	C3	111%	114%	Short-term rating and/or operating procedure
KERN-SP-T-033	Line between Shafter 115 kV To Midway 115 kV Ckt #1	34774 "MIDWAY"115 kV Bus Section 1D	C1	103%	103%	Short-term rating
KERN-SP-T-034	Line between Midway 115 kV To Navy 35R 115 kV Ckt #1	taft-universty 115 and fellows-taft 115	C3	117%	116%	Short-term rating and/or operating procedure
KERN-SP-T-035	Line between Midway 115 kV To Navy 35R 115 kV Ckt #1	taft-universty 115 and midsun-fellows 115	C3	112%	111%	Short-term rating and/or operating procedure
KERN-SP-T-036	Line between Taft A 70 kV To Taft A_J 70 kV Ckt #1	midway-midsun 115 and midway-taft 115	C3	101%	102%	Short-term rating and/or operating procedure
KERN-SP-T-037	Line between Taft A_J 70 kV To Moco_Jct 70 kV Ckt #1	midway-midsun 115 and midway-taft 115	C3	124%	125%	Short-term rating and/or operating procedure
KERN-SP-T-038	Line between Taft A_J 70 kV To Moco_Jct 70 kV Ckt #1	kern pw2-kern pw1 70 and kern pwr 115/70	C3	118%	137%	Short-term rating and/or operating procedure
KERN-SP-T-039	Line between Maricopa 70 kV To Gardner 70 kV Ckt #1	midway-midsun 115 and midway-taft 115	C3	121%	122%	Short-term rating and/or operating procedure
KERN-SP-T-040	Line between Maricopa 70 kV To Gardner 70 kV Ckt #1	kern pw2-kern pw1 70 and kern pwr 115/70	C3	108%	128%	Short-term rating and/or operating procedure
KERN-SP-T-041	Line between Gardner 70 kV To Bscl_Pld 70 kV Ckt #1	midway-midsun 115 and midway-taft 115	C3	119%	119%	Short-term rating and/or operating procedure
KERN-SP-T-042	Line between Gardner 70 kV To Bscl_Pld 70 kV Ckt #1	kern pw2-kern pw1 70 and kern pwr 115/70	C3	105%	125%	Short-term rating and/or operating procedure
KERN-SP-T-043	Line between Bscl_Pld 70 kV To Copus 70 kV Ckt #1	midway-midsun 115 and midway-taft 115	C3	118%	118%	Short-term rating and/or operating procedure
KERN-SP-T-044	Line between Bscl_Pld 70 kV To Copus 70 kV Ckt #1	kern pw2-kern pw1 70 and kern pwr 115/70	C3	103%	123%	Short-term rating and/or operating procedure
KERN-SP-T-045	Line between Wheeler 70 kV To Weedptch 70 kV Ckt #1	wheeler-sn brnrd 70 and wheeler-tejon 70	C3	127%	128%	Short-term rating and/or operating procedure
KERN-SP-T-046	Line between Tejon 70 kV To Sn Brnrd 70 kV Ckt #1	wheeler-sn brnrd 70 and wheeler-weedptch 70	C3	101%	102%	Short-term rating and/or operating procedure
KERN-SP-T-047	Line between Sn Brnrd 70 kV To Stalionj 70 kV Ckt #1	wheeler-weedptch 70 and weedptch-kerncnyn 70	C3	131%	132%	Short-term rating and/or operating procedure
KERN-SP-T-048	Line between Sn Brnrd 70 kV To Stalionj 70 kV Ckt #1	wheeler-sn brnrd 70 and wheeler-tejon 70	C3	104%	105%	Short-term rating and/or operating procedure
KERN-SP-T-049	Line between Sn Brnrd 70 kV To Stalionj 70 kV Ckt #1	wheeler-weedptch 70 and kerncnyn g-1	B	100%	101%	Re-rate or reconductor
KERN-SP-T-050	Line between Arvin 70 kV To Weedptch 70 kV Ckt #1	wheeler-sn brnrd 70 and wheeler-tejon 70	C3	122%	124%	Short-term rating and/or operating procedure
KERN-SP-T-051	Line between Arvin 70 kV To Weedptch 70 kV Ckt #1	wheeler-weedptch 70 and weedptch-kerncnyn 70	C3	113%	114%	Short-term rating and/or operating procedure
KERN-SP-T-053	Line between Arvin 70 kV To Stalionj 70 kV Ckt #1	wheeler-weedptch 70 and weedptch-kerncnyn 70	C3	131%	132%	Short-term rating and/or operating procedure
KERN-SP-T-054	Line between Arvin 70 kV To Stalionj 70 kV Ckt #1	wheeler-sn brnrd 70 and wheeler-tejon 70	C3	104%	105%	Short-term rating and/or operating procedure
KERN-SP-T-055	Line between Arvin 70 kV To Stalionj 70 kV Ckt #1	wheeler-weedptch 70 and kerncnyn g-1	B	101%	101%	Re-rate or reconductor
KERN-SP-T-056	Line between Old River 70 kV To Union Jct 70 kV Ckt #1	taft a-maricopa 70 and kern pw1-old rivr 70	C3	127%	130%	Short-term rating and/or operating procedure

ATTACHMENT X

Table 3-3.6.2: Load Forecasts modeled in Fresno and Yosemite area assessment

Fresno Area 1-in-10 year Non-Simultaneous Load Forecast			
PG&E Area Name	Summer Peak (MW)		Summer off Peak (MW)
	2014	2019	2014
Humboldt	145	154	100
Niorth Coast	706	758	330
North Valley	918	967	423
Sacramento	1,103	1,168	510
Sierra	1,219	1,321	466
North Bay	653	687	382
East Bay	838	866	654
Diablo	1,658	1,747	910
San Francisco	879	901	501
Penninsula	949	1,000	636
Stockton	1,422	1,529	740
Stanislaus	239	257	127
Yosemite	911	966	476
Fresno	2,494	2,667	1,234
Kern	1,815	1,918	1,222
Mission	1,351	1,430	653
De Anza	938	1,007	597
San Jose	1,681	1,791	770
Central Coast	649	676	485
Los Padres	574	609	458
Total	21,144	22,419	11,674

3.3.6.3 Study Results and Discussions

TPL 001: System Performance under Normal Conditions

- For the summer peak cases, there are two facilities with identified thermal overloads and no facilities with low voltage concerns under the Category A performance requirement.
- For the summer off-peak cases, there are five facilities with identified with thermal overloads and no facilities with low voltage concerns under the Category A performance requirement.

TPL 002: System Performance Following Loss of Single BES Elements and CAISO Category B: (G-1/L-1)

- For the summer peak cases, there are seven facilities with identified thermal overloads and six facilities with identified with low voltage concerns under the Category B performance requirement.
- For the summer off-peak cases, there are seven facilities with identified with thermal overloads and no facilities with low voltage concern under the Category B performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

- For the summer peak cases, there are 54 facilities with identified thermal overloads and 12 facilities with identified with low voltage concerns under the Category C performance requirement.

- For the summer off-peak cases, there are 20 facilities with identified thermal overloads and no facilities with low voltage concern under the Category C performance requirement.

Tables 3-3.6.3 to 3-3.6.5 document the worst thermal overloads and low voltage concerns identified for the summer-peak and summer off-peak conditions along with ISO-proposed solutions.

Table 3-3.6.3: Summary of thermal overloads for summer peak conditions - Fresno

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-T-016	Bank between Corcoran 115 kV To Corcoran 70 kV Ckt #2	N/A	A	Normal	105%	110%	2010	replace transformer with higher capacity
FRES-SP-T-061	Line between Corsgold 115 kV To Oakh_Jct 115 kV Ckt #1	N/A	A	Normal	<100%	110%	2015	reconductor Oakhurst 115 kV tap
FRES-SP-T-001	Bank between Los Banos 230 kV To Los Banos 70 kV Ckt #3	Los Banos 230/70 kV Bank #4	B	T-1	113%	126%	2010	Replace with higher capacity bank
FRES-SP-T-030	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Herndon - Ashlan 230 kV #1	B	L-1	<100%	105%	2015	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-038	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gregg - Ashlan 230 kV #1 1 (Drop Helm 3)	B	L-1	<100%	105%	2015	Reconductor Herndon-Ashlan
FRES-SP-T-048	Line between Chwchlla 115 kV To Certan T 115 kV Ckt #1	Woodward - Chldhosp 115 kV #1 and Kerckhof Unit 1	B	L-1/G-1	<100%	101%	2015	Rerate Certainteed tap 115 kV
FRES-SP-T-084	Line between Exchequr 70 kV To Bervlly 70 kV Ckt #1	Mariposa - Exchequr 70 kV #1	B	L-1	<100%	108%	2015	reconductor and voltage support
FRES-SP-T-109	Line between Dnuba_Jt 70 kV To Dinuba 70 kV Ckt #1	Sand Creek - Orsi Jct 70 kV #1	B	L-1	<100%	108%	2015	Reconductor Reedley-Dinuba 70 kV
FRES-SP-T-112	Line between Orosi 70 kV To Orsi Jct 70 kV Ckt #1	Reedley - Dinuba 70 kV #1	B	L-1	101%	112%	2013	Reconductor Reedley-Orosi 70 kV
FRES-SP-T-002	Bank between Los Banos 230 kV To Los Banos 70 kV Ckt #3	Los banos 230/70 kV Bank #4 and Dfs Tp - Oro Loma 115 kV #2	C	L-1/T-1	151%	162%	2010	Replace with higher capacity bank
FRES-SP-T-003	Bank between Los Banos 230 kV To Los Banos 70 kV Ckt #3	Hammons - Panoche 115 kV #1 and Los Banos 230/70 kV Bank # 4	C	L-1/T-1	144%	158%	2010	Replace with higher capacity bank
FRES-SP-T-004	Bank between Los Banos 230 kV To Los Banos 70 kV Ckt #3	Los Banos 230/70 kV #4 and Mendota 115/70 kV #1	C	T-1-1	129%	141%	2010	Replace with higher capacity bank
FRES-SP-T-005	Bank between Herndon 230 kV To Herndon 115 kV Ckt #1	Herndon 230/115 kV Bank #2 and Herndon 230/15 kV Bank #3	C	T-1-1	109%	116%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-006	Bank between Herndon 230 kV To Herndon 115 kV Ckt #2	Herndon 230/115 kV Bank #1 and Herndon 230/15 kV Bank #3	C	T-1-1	109%	117%	2010	Establish 15 minute rating, curtail load within 15 minutes

Table 3-3.6.3: Summary of thermal overloads for summer peak conditions - Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-T-007	Bank between Herndon 230 kV To Herndon 115 kV Ckt #3	Herndon 230/115 kV Bank #1 and Herndon 230/115 kV Bank #2	C	T-1-1	109%	117%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-008	Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #1	McCall 230/115 kV Bank #2 and McCall 230/115 kV Bank #3	C	T-1-1	106%	118%	2011	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-009	Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #2	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #3	C	T-1-1	104%	116%	2012	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-010	Bank between Mc Call 230 kV To Mc Call 115 kV Ckt #3	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #2	C	T-1-1	106%	118%	2011	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-011	Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #1	McCall 230/115 kV Bank #2 and McCall 230/115 kV Bank #3	C	T-1-1	105%	117%	2011	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-012	Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #2	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #3	C	T-1-1	100%	112%	2013	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-013	Bank between Mc Call 115 kV To Mc Call 115 kV Ckt #3	McCall 230/115 kV Bank #1 and McCall 230/115 kV Bank #2	C	T-1-1	105%	116%	2011	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-014	Bank between Herndon 115 kV To Herndon 115 kV Ckt #1	Herndon 230/115 kV Bank #2 and Herndon 230/15 kV Bank #3	C	T-1-1	108%	115%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-015	Bank between Herndon 115 kV To Herndon 115 kV Ckt #2	Herndon 230/115 kV Bank #1 and Herndon 230/15 kV Bank #3	C	T-1-1	108%	116%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-018	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Helms - Gregg 230 kV #1 and #2	C	DCTL	108%	121%	2011	reconductor
FRES-SP-T-031	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and Gregg - Herndon 230 kV #2 (Drop Helm 3)	C	L-1-1	141%	151%	2010	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-032	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Gregg - Helms PP 230 kV #2 and Herndon - Ashlan 230 kV #1	C	L-1-1	99%	107%	2014	Reconductor Gregg - Ashlan 230 kV #1

Table 3-3.6.3: Summary of thermal overloads for summer peak conditions - Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-T-033	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Herndon - Ashlan 230 kV #1 and Panoche - Kearney 230 kV #1	C	L-1-1	99%	106%	2015	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-034	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Panoche - Kearney 230 kV #1 and Herndon - Ashlan 230 kV #1	C	L-1-1	99%	106%	2015	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-035	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Gregg - Gates 230 kV #1 and Herndon - Ashlan 230 kV #1	C	L-1-1	99%	106%	2015	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-036	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Herndon-Kearney and Herndon-Ashlan	C	DCTL	<100%	105%	2015	Reconductor Gregg - Ashlan 230 kV #1
FRES-SP-T-037	Line between Gregg 230 kV To Fgrdn T2 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and #2	C	DCTL	180%	191%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-039	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gregg - Helms PP 230 kV #2 and Gregg - Ashlan 230 kV #1 1 (Drop Helm 3)	C	L-1-1	99%	107%	2015	Reconductor Herndon-Ashlan
FRES-SP-T-040	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gregg - Ashlan 230 kV #1 1 (Drop Helm 3) and Panoche - Kearney 230 kV #1	C	L-1-1	99%	106%	2015	Reconductor Herndon-Ashlan
FRES-SP-T-041	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Panoche - Kearney 230 kV #1 and Gregg - Ashlan 230 kV #1 1 (Drop Helm 3)	C	L-1-1	99%	106%	2015	Reconductor Herndon-Ashlan
FRES-SP-T-042	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gregg - Ashlan 230 kV #1 1 (Drop Helm 3) and Gates - Gregg 230 kV #1 230 + trip helms unit3	C	L-1-1	99%	106%	2015	Reconductor Herndon-Ashlan
FRES-SP-T-044	Line between Herndon 230 kV To Fgrdn T1 230 kV Ckt #1	Gates - Gregg 230 kV #1 and Gregg - Ashlan 230 kV #1	C	DCTL	99%	106%	2015	Reconductor Herndon-Ashlan
FRES-SP-T-045	Line between Fgrdn T1 230 kV To Ashlan 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and #2	C	DCTL	104%	109%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-046	Line between Fgrdn T2 230 kV To Ashlan 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and Gregg - Herndon 230 kV #2 (Drop Helm 3)	C	L-1-1	112%	120%	2010	Establish 15 minute rating, curtail load within 15 minutes

Table 3-3.6.3: Summary of thermal overloads for summer peak conditions - Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-T-047	Line between Fgrdn T2 230 kV To Ashlan 230 kV Ckt #1	Gregg - Herndon 230 kV #1 and #2	C	DCTL	152%	161%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-049	Line between Chwchlla 115 kV To Certan T 115 kV Ckt #1	Woodward - Chldhosp 115 kV #1 and Kerchoff 115/13 kV Bank #1	C	L-1/T-1	<100%	101%	2018	Rerate Certainteed tap 115 kV
FRES-SP-T-050	Line between Certan T 115 kV To Le Grand 115 kV Ckt #1	Clovis J1 - Sanger 115 kV #1 and Kerckhf2 - Sanger 115 kV #1	C	L-1-1	121%	111%	2010	Rerate Le Grand-Chowchilla 115 kV
FRES-SP-T-051	Line between Certan T 115 kV To Le Grand 115 kV Ckt #1	Kerckhoff - Clovis - Sanger 115 kV #1 and #2	C	DCTL	121%	111%	2010	Rerate Le Grand-Chowchilla 115 kV
FRES-SP-T-053	Line between Atwater 115 kV To Wilson A 115 kV Ckt #1	Atwater - Merced 115 kV #1 and Wilson B - El Captn 115 kV #1	C	L-1-1	105%	116%	2011	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-058	Line between Exchequr 115 kV To Le Grand 115 kV Ckt #1	Exchequr - Saxoncrk 70 kV #1 and Merced 115/70 kV Bank #2	C	L-1/T-1	110%	107%	2010	Reduce exchequer, merced falls, mcswain after first contingency
FRES-SP-T-062	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson - Atwater 115 kV #1 and Wilson A - Wilson B 115 kV #1	C	L-1-1	<100%	107%	2015	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-063	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson B - Merced 115 kV #2 and Merced 115/70 kV Bank #2	C	L-1/T-1	<100%	102%	2015	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-065	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson A - Wilson B 115 kV #1 and Wilson 230kV/Wilson B 115 kV Bank #2	C	L-1/T-1	112%	122%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-066	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson B - El Captn 115 kV #1 and Wilson B - Merced 115 kV #2	C	L-1-1	112%	125%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-067	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Atwater - Cresey T 115 kV #1 and Wilson B - Merced 115 kV #2	C	L-1-1	101%	113%	2013	Establish 15 minute rating, curtail load within 15 minutes

Table 3-3.6.3: Summary of thermal overloads for summer peak conditions - Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-T-068	Line between Wilson A 115 kV To Merced 115 kV Ckt #1	Wilson - Atwater 115 kV #1 and Wilson B - Merced 115 kV #2	C	L-1-1	101%	113%	2013	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-071	Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson A - Merced 115 kV #1 and Wilson B - El Captn 115 kV #1	C	L-1-1	110%	122%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-072	Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Atwater - Cresey T 115 kV #1 and Wilson A - Merced 115 kV #1	C	L-1-1	101%	113%	2013	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-073	Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson - Atwater 115 kV #1 and Wilson A - Merced 115 kV #1	C	L-1-1	99%	111%	2014	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-074	Line between Wilson B 115 kV To Merced 115 kV Ckt #2	Wilson-Atwater and El Capitan-Wilson	C	L-1-1	118%	133%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-082	Line between Ortiga 70 kV To Mrcysprs 70 kV Ckt #1	Livngstn - Los Banos 70 kV #1 and Canal - Santa Rta 70 kv #1	C	L-1-1	<100%	102%	2014	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-083	Line between Ortiga 70 kV To Mrcysprs 70 kV Ckt #1	Oro Loma - Dos Pals 70 kV #1 and Livngstn - Los Banos 70 kV #1	C	L-1-1	103%	115%	2012	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-087	Line between Exchequr 70 kV To Mcswainj 70 kV Ckt #1	Borden-Gregg (Drop Helms Unit 3) and Exchequr - Le Grand 115 kV #1 (Drop 34306 Unit 1)	C	L-1-1	119%	157%	2011	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-091	Line between Borden 70 kV To Cassidy 70 kV Ckt #1	Mc Call - Wahtoke 115 kV #1 and Frantdm GSU	C	L-1/T-1	<100%	105%	2015	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-092	Line between Borden 70 kV To Cassidy 70 kV Ckt #1	Frantdm GSU and Tvy Vlly - Reedley 70 kV #1	C	L-1/T-1	<100%	107%	2015	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-096	Line between Sanger 115 kV To Cal Ave 115 kV Ckt #1	Mc Call - Danishcm 115 kV #1 and Wst Frso - Mc Call 115 kV #1	C	L-1-1	108%	115%	2010	Establish 15 minute rating, curtail load within 15 minutes

Table 3-3.6.3: Summary of thermal overloads for summer peak conditions - Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-T-097	Line between Sanger 115 kV To Cal Ave 115 kV Ckt #1	McCall-West Fresno & Mc Call - California	C	DCTL	108%	115%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-098	Line between Mc Call 115 kV To Danishcm 115 kV Ckt #1	Cal Ave - Sanger 115 kV #1 and Wst Frso - Mc Call 115 kV #1	C	L-1-1	116%	129%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-099	Line between Mc Call 115 kV To Wst Frno 115 kV Ckt #1	Mc Call - Danishcm 115 kV #1 and Cal Ave - Sanger 115 kV #1	C	L-1-1	103%	111%	2012	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-100	Line between Mc Call 115 kV To Gaurd J1 115 kV Ckt #1	KcognJct - Kingsbrg 115 kV #1 (Drop Kingsburg Unit 1) and Kingsburg - Gwf Hep 115 kV #1	C	L-1-1	108%	118%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-101	Line between Reedley 115 kV To Piedra_1 115 kV Ckt #1	SngrJct - Reedley 115 kV #1 (Drop Sangerco Unit 1) and Mc Call - Wahtoke 115 kV #1	C	L-1-1	128%	146%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-102	Line between Kings_J1 115 kV To Kings J2 115 kV Ckt #1	Mc Call - Gaurd J2 115 kV #1 and Kingsburg - Gwf Hep 115 kV #1	C	L-1-1	122%	134%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-103	Line between Danishcm 115 kV To Cal Ave 115 kV Ckt #1	Cal Ave - Sanger 115 kV #1 and Wst Frso - Mc Call 115 kV #1	C	L-1-1	113%	126%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-104	Line between Barton115 kV To Herndon 115 kV Ckt #1	Manchester - Herndon 115 kV #1 and Woodward - Chldhosp 115 kV #1	C	L-1-1	102%	110%	2013	Rerate Barton-Herndon 115 kV
FRES-SP-T-105	Line between Manchstr 115 kV To Herndon 115 kV Ckt #1	Barton - Herndon 115 kV #1 and Woodward - Chldhosp 115 kV #1	C	L-1-1	103%	112%	2012	Rerate Manchester-Herndon 115 kV
FRES-SP-T-107	Line between Kings J2 115 kV To Kingsburg 115 kV Ckt #1	Mc Call - Gaurd J2 115 kV #1 and Kingsburg - Gwf Hep 115 kV #1	C	L-1-1	99%	108%	2014	Establish 15 minute rating, curtail load within 15 minutes

Table 3-3.6.3: Summary of thermal overloads for summer peak conditions - Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-T-108	Line between Kingsburg 115 kV To Gaurd J1 115 kV Ckt #1	KcognJct - Kingsbrg 115 kV #1 (Drop Kingsburg Unit 1) and Kingsburg - Gwf Hep 115 kV #1	C	L-1-1	123%	135%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-110	Line between Dnuba_Jt 70 kV To Dinuba 70 kV Ckt #1	Mc Call - Wahtoke 115 kV #1 and Sand Creek - Orsi Jct 70 kV #1	C	L-1-1	101%	113%	2013	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-111	Line between Dnuba_Jt 70 kV To Dinuba 70 kV Ckt #1	Wahtoke - Reedley 115 kV #1 and Sand Creek - Orsi Jct 70 kV #1	C	L-1-1	99%	110%	2014	Reconductor this section of Reedley-Dinuba No. 1 70 kV
FRES-SP-T-113	Line between Orosi 70 kV To Orsi Jct 70 kV Ckt #1	Mc Call - Wahtoke 115 kV #1 and Reedley - Dinuba 70 kV #1 (Drop Dinuba Unit 1)	C	L-1-1	105%	118%	2011	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-114	Line between Orosi 70 kV To Orsi Jct 70 kV Ckt #1	Wahtoke - Reedley 115 kV #1 and Reedley - Dinuba 70 kV #1 (Drop Dinuba Unit 1)	C	L-1-1	103%	116%	2012	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-115	Line between Orosi 70 kV To Orsi Jct 70 kV Ckt #1	Reedley - Dinuba 70 kV #1 and Reedley 115/70 kV Bank #2	C	L-1/T-1	102%	115%	2013	Reconductor Reedley-Orosi 70 kV
FRES-SP-T-116	Line between Calfax 70 kV To Schlndlr 70 kV Ckt #1	Gats2_tp 70 kV - Colinga2 70 kV #1 and Gates 230115 kB Bank #1	C	L-1/T-1	113%	125%	2010	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-117	Line between Templt7 70 kV To Templ_J 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	C	T-1-1	100%	119%	2014	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-118	Line between Templ_J 70 kV To Psa Rbls 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	C	T-1-1	100%	119%	2014	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-119	Line between San Migl 70 kV To Psa Rbls 70 kV Ckt #1	Schindler 115/70 kV Bank #1 and Gates 115/70 kV Bak #2	C	T-1-1	117%	152%	2011	Establish 15 minute rating, curtail load within 15 minutes

Table 3-3.6.3: Summary of thermal overloads for summer peak conditions - Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-T-120	Line between San Migl 70 kV To Psa Rbls 70 kV Ckt #1	Colnga 1 -Jacalito 70 kV #1 and Colnga 2 to Tornado 70 kV #1 (Drop Chv Coal Unit 1)	C	L-1-1	108%	127%	2011	Establish 15 minute rating, curtail load within 15 minutes
FRES-SP-T-121	Line between Herndon-Barton 115 kV Ckt #1	Helm-McCall and Gates-McCall 230 kV Lines	C	DCTL	<95%	105%	2015	Rerate Barton-Herndon 115 kV
FRES-SP-T-122	Line between Herndon-Manchester 115 kV Ckt #1	Helm-McCall and Gates-McCall 230 kV Lines	C	DCTL	<95%	105%	2015	Rerate Manchester-Herndon 115 kV
FRES-SP-T-123	Line between Helm-McCall 230 kV Ckt #1	Gates - Gregg 230 kV #1 and Gates-McCall 230 kV Lines	C	DCTL	<95%	116%	2015	Reconductor Helm-McCall 230 kV
FRES-SP-T-124	Line between Panoche-Helm 230 kV Ckt #1	Gates - Gregg 230 kV #1 and Gates-McCall 230 kV Lines	C	DCTL	<95%	119%	2015	Reconductor Panoche-Helm 230 kV

Table 3-3.6.4: Summary of low voltages for summer peak conditions - Fresno

ID	Substation	Worst Contingency	Category	Category Description	Min Post-Cont Voltage (PU)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SP-V-003	DINUBA 70	L-1 Reedley - Dinuba 70 kV #1 (Drop Dinuba Unit 1)	B	L-1	0.91	0.89	2014	Reedley-Orosi 70 kV reconductoring
FRES-SP-V-029	STOREY 2 230	L-1 Borden-Gregg 230 kV #1 and L-1 Wilson-Gregg 230 kV #1	C	DCTL	0.9	0.88	2014	Install reactive support at Borden
FRES-SP-V-030	BORDEN 230	L-1 Borden-Gregg 230 kV #1 and L-1 Wilson-Gregg 230 kV #1	C	DCTL	0.9	0.88	2014	Install reactive support at Borden
FRES-SP-V-036	BSWLL TP 70	L-1 McCall-Kingsburg 230 kV #1 and L-1 McCall-Kingsburg 230 kV #2	C	DCTL	0.9	0.88	2014	115/70 kV Corcoran transformer replacement
FRES-SP-V-037	JGBSWLL 70	L-1 McCall-Kingsburg 230 kV #1 and L-1 McCall-Kingsburg 230 kV #2	C	DCTL	0.89	0.87	2014	115/70 kV Corcoran transformer replacement
FRES-SP-V-038	ANGIOLA 70	L-1 McCall-Kingsburg 230 kV #1 and L-1 McCall-Kingsburg 230 kV #2	C	DCTL	0.89	0.86	2014	115/70 kV Corcoran transformer replacement
FRES-SP-V-039	BOSWELL 70	L-1 McCall-Kingsburg 230 kV #1 and L-1 McCall-Kingsburg 230 kV #2	C	DCTL	0.9	0.87	2014	115/70 kV Corcoran transformer replacement

Table 3-3.6.5: Summary of thermal overloads for summer off-peak conditions - Fresno

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SOP-T-001	Line between Gates 500 kV To Midway 500 kV Ckt #1	N/A	A	Normal	100%		2014	curtail Path 15 flow
FRES-SOP-T-003	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	N/A	A	Normal	121%		2014	Reconductor Panoche-McMullin 230 kV line section
FRES-SOP-T-011	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	N/A	A	Normal	111%		2014	Reconductor McMullin-Kearney 230 kV line section
FRES-SOP-T-019	Line between Kearney 230 kV To Herndon 230 kV Ckt #1	N/A	A	Normal	100%		2014	Interim temperature adjusted rating
FRES-SOP-T-029	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	N/A	A	Normal	118%		2014	Reconductor McCall-Henrietta 230 kV line section
FRES-SOP-T-004	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	panoche-helm 230 kV line	B	L-1	118%		2014	Reconductor Panoche-McMullin 230 kV line section
FRES-SOP-T-012	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	panoche-helm 230 kV line	B	L-1	108%		2014	Reconductor McMullin-Kearney 230 kV line section
FRES-SOP-T-024	Line between Panoche 230 kV To Helm 230 kV Ckt #1	gates-mcall 230 kV line trip helms 1 pump	B	L-1	103%		2014	Reconductor Panoche-Helm 230 kV
FRES-SOP-T-030	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	panoche-helm 230 kV line	B	L-1	127%		2014	Reconductor McCall-Henrietta 230 kV line section
FRES-SOP-T-046	Line between Hentap2 230 kV To Gates 230 kV Ckt #1	gates-gregg 230 kV line trip helms 1 pump	B	L-1	131%		2014	Upgrade terminal equipment at Gates
FRES-SOP-T-047	Line between Hentap2 230 kV To Gates 230 kV Ckt #1	panoche-helm 230 kV line	B	L-1	103%		2014	Upgrade terminal equipment at Gates
FRES-SOP-T-052	Line between Gates 230 kV To Midway 230 kV Ckt #1	gates 500/230 kV bank 11 trip helms 1 pump	B	T-1	118%		2014	Interim temperature adjusted rating
FRES-SOP-T-053	Line between Arco 230 kV To Midway 230 kV Ckt #1	gates 500/230 kV bank 11 trip helms 1 pump	B	T-1	106%		2014	Interim temperature adjusted rating

Table 3-3.6.5: Summary of thermal overloads for summer off-peak conditions – Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SOP-T-002	Line between Warnervl 230 kV to Wilson 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C	DCTL	101%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-005	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C	DCTL	129%		2014	Reconductor Panoche-McMullin 230 kV line section
FRES-SOP-T-006	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Borden-Gregg and Wilson-Gregg	C	DCTL	119%		2014	Reconductor Panoche-McMullin 230 kV line section
FRES-SOP-T-007	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C	DCTL	116%		2014	Reconductor Panoche-McMullin 230 kV line section
FRES-SOP-T-008	Line between Panoche 230 kV To McMulln1 230 kV Ckt #1	Barton-Sanger and Manchester-Sanger	C	DCTL	109%		2014	Reconductor Panoche-McMullin 230 kV line section
FRES-SOP-T-009	Line between Panoche 230 kV to McMulln1 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C	DCTL	152%		2014	Reconductor Panoche-McMullin 230 kV line section
FRES-SOP-T-010	Line between Panoche 230 kV to McMulln1 230 kV Ckt 1	Helm-McCall and Gates-McCall	C	DCTL	122%		2014	Reconductor Panoche-McMullin 230 kV line section
FRES-SOP-T-013	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C	DCTL	119%		2014	Reconductor McMullin-Kearney 230 kV line section
FRES-SOP-T-014	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	Borden-Gregg and Wilson-Gregg	C	DCTL	109%		2014	Reconductor McMullin-Kearney 230 kV line section
FRES-SOP-T-015	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C	DCTL	106%		2014	Reconductor McMullin-Kearney 230 kV line section
FRES-SOP-T-016	Line between McMulln1 230 kV To Kearney 230 kV Ckt #1	Barton-Sanger and Manchester-Sanger	C	DCTL	100%		2014	Reconductor McMullin-Kearney 230 kV line section
FRES-SOP-T-017	Line between McMulln1 230 kV to Kearney 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C	DCTL	141%		2014	Reconductor McMullin-Kearney 230 kV line section

Table 3-3.6.5: Summary of thermal overloads for summer off-peak conditions – Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SOP-T-018	Line between McMulln1 230 kV to Kearney 230 kV Ckt 1	Helm-McCall and Gates-McCall	C	DCTL	112%		2014	Reconductor McMullin-Kearney 230 kV line section
FRES-SOP-T-020	Line between Kearney 230 kV To Herndon 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C	DCTL	110%		2014	Interim temperature adjusted rating
FRES-SOP-T-021	Line between Kearney 230 kV To Herndon 230 kV Ckt #1	Borden-Gregg and Wilson-Gregg	C	DCTL	100%		2014	Interim temperature adjusted rating
FRES-SOP-T-022	Line between Kearney 230 kV to Herndon 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C	DCTL	132%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-023	Line between Kearney 230 kV to Herndon 230 kV Ckt 1	Helm-McCall and Gates-McCall	C	DCTL	104%		2014	Interim temperature adjusted rating
FRES-SOP-T-025	Line between Panoche 230 kV to Helm 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C	DCTL	160%		2014	Reconductor Panoche-Helm 230 kV
FRES-SOP-T-026	Line between Helm 230 kV to MC Call 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C	DCTL	155%		2014	Reconductor Helm-McCall 230 kV
FRES-SOP-T-027	Line between Panoche 230 kV to Gates 230 kV Ckt 1	Gates-Gregg and Gates-McCall	C	DCTL	118%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-028	Line between Panoche 230 kV to Gates 230 kV Ckt 2	Gates-Gregg and Gates-McCall	C	DCTL	118%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-031	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Panoche-Kearney and Panoche-Helm	C	DCTL	131%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-032	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Panoche-Kearney and Helm-McCall	C	DCTL	128%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-033	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Gates-Panoche #1 and #2	C	DCTL	115%		2014	Reconductor McCall-Henrietta 230 kV line section
FRES-SOP-T-034	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Panoche-Gates #1 and #2	C	DCTL	115%		2014	Reconductor McCall-Henrietta 230 kV line section
FRES-SOP-T-035	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C	DCTL	109%		2014	Reconductor McCall-Henrietta 230 kV line section

Table 3-3.6.5: Summary of thermal overloads for summer off-peak conditions – Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SOP-T-036	Line between MC Call 230 kV To Hentap2 230 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C	DCTL	106%		2014	Reconductor McCall-Henrietta 230 kV line section
FRES-SOP-T-037	Line between Mc Call 230 kV to Hentap2 230 kV Ckt 1	Panoche-Kearney and Gates-Gregg	C	DCTL	102%		2014	Reconductor McCall-Henrietta 230 kV line section
FRES-SOP-T-038	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Wilson-Gregg and Wilson-Borden	C	DCTL	108%		2014	SPS to trip 1 of 2 Helms pumps
FRES-SOP-T-039	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Panoche-Kearney and Panoche-Helm	C	DCTL	105%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-040	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Panoche-Kearney and Helm-McCall	C	DCTL	104%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-041	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Gates-Panoche #1 and #2	C	DCTL	103%		2014	SPS to trip 1 of 2 Helms pumps
FRES-SOP-T-043	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Borden-Gregg and Wilson-Gregg	C	DCTL	102%		2014	SPS to trip 1 of 2 Helms pumps
FRES-SOP-T-044	Line between Hentap1 230 kV To Gates 230 kV Ckt #1	Bellota-Melones and Warnerville-Wilson	C	DCTL	102%		2014	SPS to trip 1 of 2 Helms pumps
FRES-SOP-T-045	Line between Hentap1 230 kV to Gates 230 kV Ckt 1	Helm-McCall and Gates-McCall	C	DCTL	117%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-048	Line between Hentap2 230 kV To Gates 230 kV Ckt #1	Panoche-Kearney and Panoche-Helm	C	DCTL	106%		2014	Upgrade terminal equipment at Gates
FRES-SOP-T-049	Line between Hentap2 230 kV To Gates 230 kV Ckt #1	Panoche-Kearney and Helm-McCall	C	DCTL	104%		2014	Upgrade terminal equipment at Gates
FRES-SOP-T-050	Line between Hentap2 230 kV to Gates 230 kV Ckt 1	Panoche-Kearney and Gates-Gregg	C	DCTL	133%		2014	Upgrade terminal equipment at Gates
FRES-SOP-T-051	Line between Henrieta 230 kV to Henrieta 115 kV Ckt # 3	Helm-McCall and Gates-McCall	C	DCTL	113%		2011	Develop 30 min rating
FRES-SOP-T-054	Line between Certain T 115kV to Le Grand 115 kV Ckt #1	Helm-McCall and Gates-McCall	C	DCTL	108%		2014	Reconductor Certainteed-Legrand 115 kV line section

Table 3-3.6.5: Summary of thermal overloads for summer off-peak conditions – Fresno (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
FRES-SOP-T-055	Line between Le Grand 115 kV to Dairyland 115 kV Ckt #1	Gates-Gregg and Gates-McCall	C	DCTL	104%		2014	Trip 2 pumps
FRES-SOP-T-062	Line between Sanger 115 kV To Mc Call 115 kV Ckt #3	McCall-Sanger #1 and #2	C	DCTL	101%		2014	Interim temperature adjusted rating
FRES-SOP-T-063	Line between Contadna 115 kV to Gwf_Hep 115 kV Ckt #1	Helm-McCall and Gates-McCall	C	DCTL	104%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-064	Line between Gwf_Hep 115 kV to Lprn Jct 115 kV Ckt #1	Helm-McCall and Gates-McCall	C	DCTL	104%		2014	SPS to trip 2 of 2 Helms pumps
FRES-SOP-T-065	Line between Henrieta 115 to 34519LPRN JCT115 1	Helm-McCall and Gates-McCall	C	DCTL	113%		2014	Interim temperature adjusted rating

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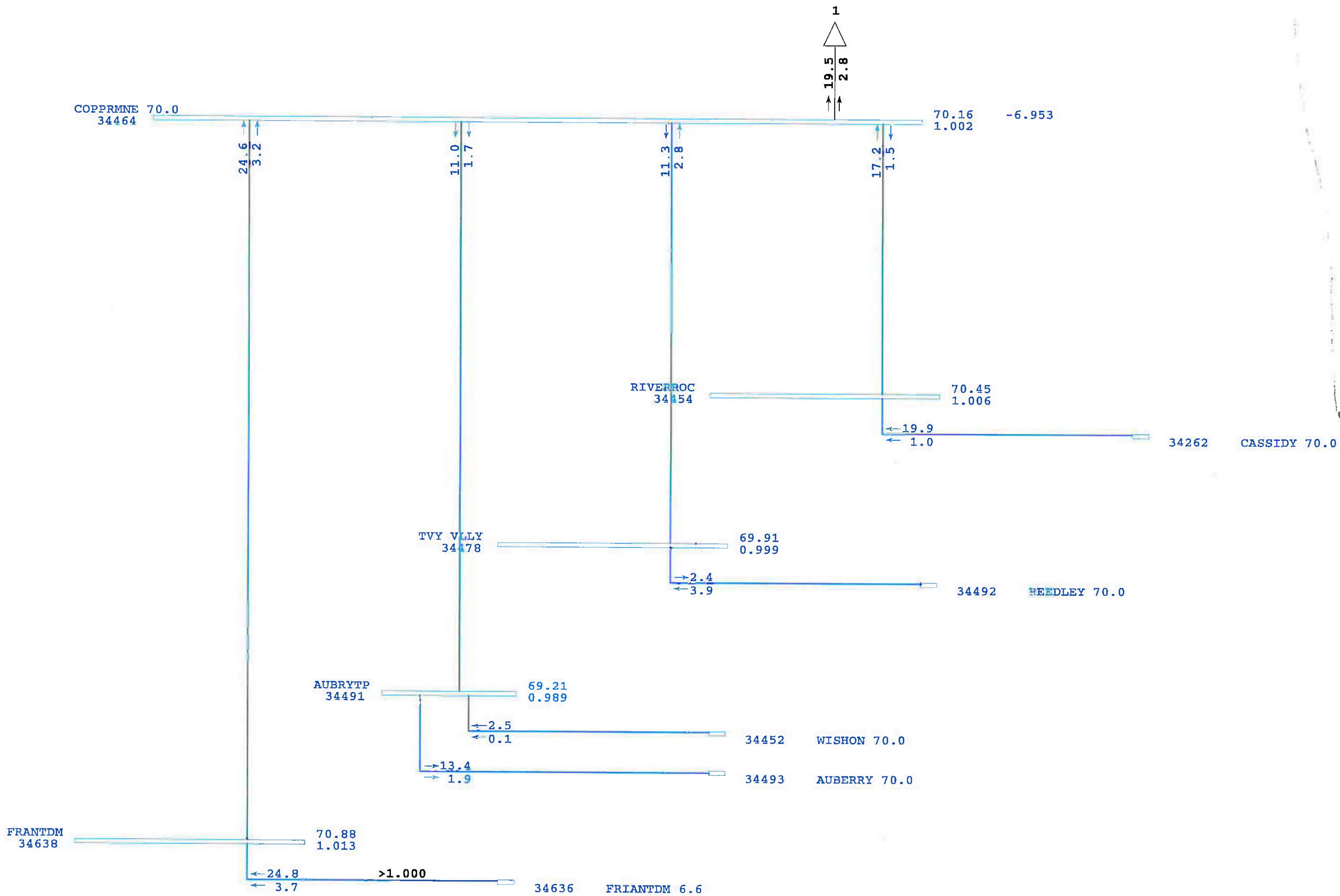


P mis = 0.0001 MW

Q mis = 0.0001 MVAR

General Electric International, Inc. PSLF Program Thu Jan 06 11:50:54 2011 2010plan\hs14\hs14.sav

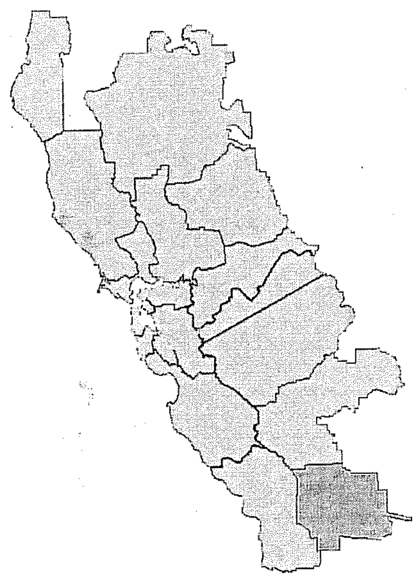
	PG&E 2009 TRANSMISSION EXPANSION PLAN ASSESSMENT 2014 SUMPK: PG&E SYSTEM CASE (1-IN-5 LOAD)	04/14/09	MW/MVAR Rating = 1

ATTACHMENT Z

3.3.7 Kern Area

3.3.7.1 Area Description

The Kern area is located south of the Yosemite-Fresno area and north of SCE's service territory. Midway Substation, one of the largest substations in the PG&E system is located in Kern Division and has connections to PG&E's Diablo Canyon, Gates, and Los Banos substations as well as SCE's Vincent Substation. The figure below depicts the geographical location of Kern area.



The bulk of the power that interconnects at Midway Substation transfers onto the 500 kV systems. A substantial amount also reaches neighboring transmission systems through Midway's 230 and 115 kV interconnections to the local areas. These interconnections include 115 kV lines to Yosemite-Fresno (north) as well as 115 and 230 kV lines to Los Padres (west). Electric customers in Kern area are served primarily through the 230/115 kV transformers at Midway and Kern Power Plant substations and through local generation power plants connected to the lower voltage transmission network.

Load forecasts indicate that the Kern area should reach its summer peak demand of 1815 MW by 2014 and 1918 MW by 2019. Load is increasing at a rate of about 22 MW per year. Accordingly, system assessments in this area include the technical studies for the scenarios under these load assumptions for summer-peak condition

3.3.7.2 Area-Specific Assumptions and System Conditions

The Kern area study was performed in a manner consistent with the general study methodology and assumptions described in Chapter 2. The ISO secured website lists the contingencies that were studied as part of this assessment. In additional, specific assumptions and methodology applied to Kern area study are provided below in this section

Generation

Generation resources in Kern area consist of market, QF and self-generating units. Table 3-3.7.1 lists all generating plants in Kern area and modeled parameters for the 2014 and 2019 Peak Analysis respectively.

Load Forecast

Loads within the Kern area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 3-3.7.2 shows loads modeled for neighboring local areas in PG&E system in the Kern area assessment as well.

Table 3-3.7.1: Generator in Kern Area

Plant Name	Max Capacity (MW)
Badger Creek (PSE)	49
Chalk Cliff	48
Cymric Cogen (Chevron)	21
Cadet (Chev USA)	12
Dexzel	33
Discovery	44
Double C (PSE)	45
Elk Hills	623
Frito Lay	8
Hi Sierra Cogen	49
Kern	177
Kern Canyon Power House	11
Kernfront	49
Kern Ridge (South Belridge)	76
La Paloma Generation	926
Midsun	25
Mt. Poso	56
Navy 35R	65
Oildale Cogen	40
Bear Mountain Cogen (PSE)	69
Live Oak (PSE)	48
McKittrick (PSE)	45
Rio Bravo Hydro	11
Shell S.E. Kern River	27
Solar Tannenhill	18
Sunset	225
North Midway (Texaco)	24
Sunrise (Texaco)	338
Sunset (Texaco)	239
Midset (Texaco)	42
Lost Hills (Texaco)	9
Ultra Power (OGLE)	45
University Cogen	36
Total	**3532**
Kern Area Pumping Plants	
Wheeler Ridge Pumping Plant	53
Wind Gap Pumping Plant	130
Buena Vista Pumping Plant	58
Total	**241**

Table 3-3.7.2: Summer Peak Load Forecasts modeled in Kern area assessment

Kern Area 1-in-10 year Non-Simultaneous Load Forecast		
PG&E Area Name	Summer Peak (MW)	
	2014	2019
Humboldt	145	154
Niorth Coast	706	758
North Valley	918	967
Sacramento	1,103	1,168
Sierra	1,219	1,321
North Bay	653	687
East Bay	838	866
Diablo	1,658	1,747
San Francisco	879	901
Penninsula	949	1,000
Stockton	1,422	1,529
Stanislaus	239	257
Yosemite	911	966
Fresno	2,494	2,667
Kern	**1,815**	**1,918**
Mission	1,351	1,430
De Anza	938	1,007
San Jose	1,681	1,791
Central Coast	649	676
Los Padres	574	609
Total	21,144	22,419

3.3.7.3 Study Results and Discussions

TPL 001: System Performance under Normal Conditions

- For the summer peak cases, there are no facilities with identified thermal overloads and voltage concerns under the Category A performance requirement.

TPL 002: System Performance Following Loss of Single BES Elements and CAISO Category B: (G-1/L-1)

- For the summer peak cases, there are no facilities with identified thermal overloads and voltage concerns under the Category B performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

- There are 11 facilities with identified thermal overloads and no facilities with identified voltage concerns under the Category C performance requirement.

Table 3-3.7.3 documents the worst thermal overloads and voltage concerns identified for the summer peak conditions along with ISO-proposed solutions.

Table 3-3.7.3: Summary of thermal overloads for summer peak conditions - Kern

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
KERN-SP-T-001	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3	kern pp 230/115 4 and kern pp 230/115 5	C	T-1-1	134%	156%	2010	Replace banks 3 and 3a with a 420 MVA transformer in 2012. Establish 15 minute rating, curtail load within 15 minutes for 2010 and 2011
KERN-SP-T-002	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3	30945 "KERN PP" 230 kV Bus Section 1	C	Bus	130%	130%	2010	Replace banks 3 and 3a with a 420 MVA transformer in 2012. Establish 15 minute rating, curtail load within 15 minutes for 2010 and 2011
KERN-SP-T-003	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3	kern pp 230/115 4 and kern pp 230/115 5	C	T-1-1	115%	156%	2013	Replace banks 3 and 3a with a 420 MVA transformer in 2012. Establish 15 minute rating, curtail load within 15 minutes for 2010 and 2011
KERN-SP-T-004	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3	pse-3-kern pwr 115 and kern pwr-kern pp115	C	L-1-1	104%	108%	2010	Replace banks 3 and 3a with a 420 MVA transformer in 2012. Establish 15 minute rating, curtail load within 15 minutes for 2010 and 2011
KERN-SP-T-005	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3a	kern pp 230/115 4 and kern pp 230/115 5	C	T-1-1	134%	131%	2010	Replace banks 3 and 3a with a 420 MVA transformer in 2012. Establish 15 minute rating, curtail load within 15 minutes for 2010 and 2011

Table 3-3.7.3: Summary of thermal overloads for summer peak conditions – Kern (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
KERN-SP-T-006	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3a	kern pp 230/115 4 and kern pp 230/115 5	C	T-1-1	115%	131%	2011	Replace banks 3 and 3a with a 420 MVA transformer in 2012. Establish 15 minute rating, curtail load within 15 minutes for 2010 and 2011
KERN-SP-T-007	Bank between Kern PP 230 kV To Kern Pwr 115 kV Ckt #3a	30945 "KERN PP" 230 kV Bus Section 1	C	Bus	111%	111%	2010	Replace banks 3 and 3a with a 420 MVA transformer in 2012. Establish 15 minute rating, curtail load within 15 minutes for 2010 and 2011
KERN-SP-T-011	Bank between Midway 230 kV To Midway 115 kV Ckt #2a	midway 230/115 and midway 230/115 3	C	T-1-1	101%	105%	2013	Establish 15 minute rating, curtail load within 15 minutes
KERN-SP-T-019	Bank between Taft 115 kV To Taft A 70 kV Ckt #2	taft 115/70 and slr-tann g-1	C	L-1-1	103%	105%	2010	Establish 15 minute rating, curtail load within 15 minutes
KERN-SP-T-022	Line between Stckdl Jt 2 230 kV To Midway 230 kV Ckt #1	Midway-Kern #1 and #4 230 kV line outage	C	DCTL	101%	118%	2013	Rerate this section of Midway-Kern No. 3 230 kV
KERN-SP-T-024	Line between Semitrpc 115 kV To Midway 115 kV Ckt #1	midway-smyrna 115 and famoso-cawelo 115	C	L-1-1	124%	127%	2010	Establish 15 minute rating, curtail load within 15 minutes
KERN-SP-T-025	Line between Semitrpc 115 kV To Midway 115 kV Ckt #1	34774 "MIDWAY"115 kV Bus Section 1E	C	Bus	111%	111%	2010	Rerate Semitropic-Midway No. 1 115 kV line
KERN-SP-T-026	Line between Westpark 115 kV To Kern Pwr 115 kV Ckt #1	westpark-kern pwr 115 2 and kern pwr-magunden 115	C	L-1-1	<100%	103%	2015	Establish 15 minute rating, curtail load within 15 minutes
KERN-SP-T-027	Line between Westpark 115 kV To Kern Pwr 115 kV Ckt #2	westpark-kern pwr 115 1 and kern pwr-magunden 115	C	L-1-1	<100%	103%	2015	Establish 15 minute rating, curtail load within 15 minutes

Table 3-3.7.3: Summary of thermal overloads for summer peak conditions – Kern (cont'd)

ID	Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)		Exp. Yr. of Occurrence	ISO Proposed Solution
					2014	2019		
KERN-SP-T-031	Line between Kern Oil Jct 115 kV To Magunden 115 kV Ckt #1	westpark-kern pwr 115 1 and westpark-kern pwr 115 2	C	L-1-1	<100%	105%	2015	Rerate this section of Kern-Magunden witco 115 kV
KERN-SP-T-032	Line between Ganso 115 kV To Midway 115 kV Ckt #1	midway-semitrpc 115 and famoso-cawelo 115	C	L-1-1	111%	114%	2010	Establish 15 minute rating, curtail load within 15 minutes
KERN-SP-T-034	Line between Midway 115 kV To Navy 35R 115 kV Ckt #1	taft-universty 115 and fellows-taft 115	C	L-1-1	117%	116%	2010	Short-term rating and/or operating procedure
KERN-SP-T-035	Line between Midway 115 kV To Navy 35R 115 kV Ckt #1	taft-universty 115 and midsun-fellows 115	C	L-1-1	112%	111%	2010	Short-term rating and/or operating procedure

3.3.7.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

Thermal Overload Mitigations

Kern PP 230/115 kV #3 Bank

The Kern PP 230/115 kV #3 and 3a Bank piggybacked transformer banks overload in the 2014 and 2019 summer peak cases immediately following the kern pp 230/115 ckt 4 and kern pp 230/115 ckt 5 overlapping contingency to 134% and 156%. The mitigation plan is to Replace banks 3 and 3a with a 420 MVA transformer in 2012 as part of a maintenance project. The interim mitigation plan for 2010 and 2011 is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency. If SCADA installation is required then the interim plan implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Midway 230/115 kV #2a Bank
The Midway 230/115 kV #2a Bank transformer bank overloads in the 2014 and 2019 summer peak cases immediately following the midway 230/115 ckt 1 and midway 230/115 ckt 3 overlapping contingency to 101% and 105%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2013.

Taft 115/70 kV #2 Bank
The Taft 115/70 kV #2 Bank transformer bank overloads in the 2014 and 2019 summer peak cases immediately following the Taft 115/70 ckt 1 and slr-tann g-1 overlapping contingency to 103% and 105%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the interim plan implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Stckdl Jt-Midway 230 kV Ckt #1 Line
The line section between Stckdl Jt 2 230 kV To Midway 230 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases immediately following the Midway-Kern #1 and #4 230 kV double circuit tower line outage to 101% and 118%. The mitigation plan is to rerate this section of Midway-Kern No. 3 230 kV line by 2013.

Semitropic-Midway 115 kV Ckt #1 Line
The line between Semitropic 115 kV To Midway 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases immediately following the Midway-Smyrna 115 and Famoso-Cawelo 115 overlapping line contingency to 124% and 127%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Westpark-Kern Pwr 115 kV Ckt #1 Line
The line between Westpark 115 kV To Kern Pwr 115 kV Ckt #1 overload in the 2019 summer peak case for the Westpark-Kern pwr 115 ckt 2 and Kern pwr-Magunden 115 overlapping contingency to 103%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2015.

Westpark-Kern Pwr 115 kV Ckt #2 Line
The line between Westpark 115 kV To Kern Pwr 115 kV Ckt #2 overload in the 2019 summer peak case for the Westpark-Kern pwr 115 ckt 1 and Kern pwr-Magunden 115 overlapping contingency to 103%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2015.

Ganso-Midway 115 kV Ckt #1 Line
The line between Ganso 115 kV To Midway 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases for the Midway-Semitropic 115 and Famoso-Cawelo 115 overlapping contingency to 111% and 114%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Midway-Navy 35R 115 kV Ckt #1 Line
The line between Midway 115 kV To Navy 35R 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases for the Taft-University 115 and Fellows-Taft 115 overlapping contingency to 117% and 116%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011.

Voltage Concerns Mitigations

- No voltage concerns were identified.

3.3.7.5 Key Conclusions

Based on the ISO study assessment, the northern Kern Area had:

- No overloads or voltage concerns under normal conditions;
- No overloads or voltage concerns under single contingency conditions; and
- Numerous overloads caused by numerous critical multiple contingencies under summer peak conditions.

Some of the overloads will be resolved by a planned maintenance project to upgrade the 230/115 kV transformers at Kern PP switchyard. For the remaining overloads, the ISO proposed operational solutions.

Western Grid Development, LLC proposed a battery storage reliability-driven project, the Weedpatch 70 kV Energy Storage Project, to address reliability concerns in the Kern area. The initial capital cost of the Weedpatch project is $4.5 million, with additional capital costs to be incurred as the battery capabilities are increased. Western Grid Development, LLC proposed to build and own the battery storage projects, to turn the facilities over to the ISO's operational control. However, ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territiry in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO results posted on September 15, 2009 that showed overloads in the Weedpatch area were flawed due to incorrect modeling information that did not reflect an existing operating procedure to open the Weedpatch CB42 breaker during the summer.

The correct results with this operating procedure to open the Weedpatch CB 42 have been reflected in this report. This correction addresses the Weedpatch area overloads. Thus, neither the Weedpatch 70 kV Energy Storage Project, nor any other transmission project, is needed because there is no identified reliability need in this area.

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procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Westpark 115 kV To Kern Pwr 115 kV Ckt #1 Line

The line between Westpark 115 kV To Kern Pwr 115 kV Ckt #1 overload in the 2019 summer peak case for the Westpark-Kern pwr 115 ckt 2 and Kern pwr-Magunden 115 overlapping contingency to 103%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2015.

Westpark 115 kV To Kern Pwr 115 kV Ckt #2 Line

The line between Westpark 115 kV To Kern Pwr 115 kV Ckt #2 overload in the 2019 summer peak case for the Westpark-Kern pwr 115 ckt 1 and Kern pwr-Magunden 115 overlapping contingency to 103%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2015.

Ganso 115 kV To Midway 115 kV Ckt #1 Line

The line between Ganso 115 kV To Midway 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases for the Midway-Semitropic 115 and Famoso-Cawelo 115 overlapping contingency to 111% and 114%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011 and load shedding would need to be performed in 2010 by proactively sending operators to load tripping locations, as needed.

Midway 115 kV To Navy 35R 115 kV Ckt #1 Line

The line between Midway 115 kV To Navy 35R 115 kV Ckt #1 overloads in the 2014 and 2019 summer peak cases for the Taft-University 115 and Fellows-Taft 115 overlapping contingency to 117% and 116%. The mitigation plan is to establish a 15 minute rating and an operating procedure and install SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2010. If SCADA installation is required then the implementation date may need to be delayed from 2010 to 2011.

Voltage Concerns Mitigations

No voltage concerns were identified.

3.3.7.5 Key Conclusions

Based on the ISO study assessment, the northern Kern Area had:

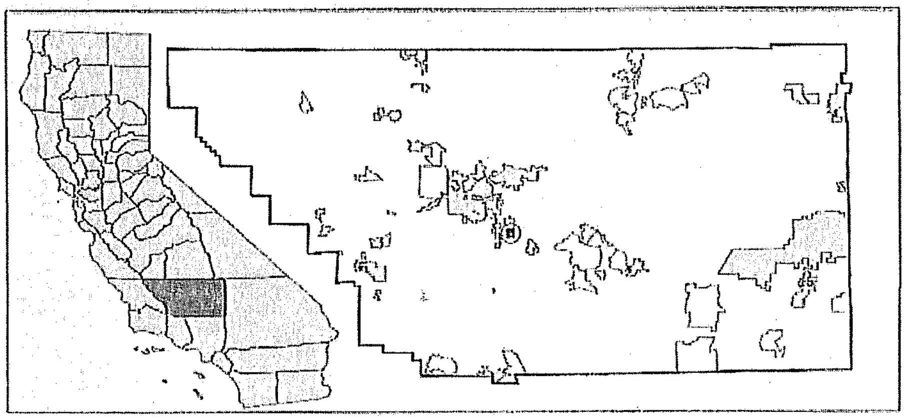
- No overloads or voltage concerns under normal conditions.
- No overloads or voltage concerns under single contingency conditions.
- Numerous overloads caused by numerous critical multiple contingencies under summer peak conditions.

Some of the overloads will be resolved by a planned maintenance project to upgrade the 230/115 kV transformers at Kern PP switchyard. For the remaining overloads, the ISO proposed operational solutions.

The ISO results posted on September 15, 2009 showed overloads in the Weedpatch area were flawed based on incorrect modeling information provided by PG&E. These results will be revised and reported in the 2010 TPP report. PG&E currently has an operating procedure in place to open Weedpatch CB 42 and address the Weedpatch area overloads. As discussed above, the Weedpatch 70 kV Energy Storage Project is being recommended for rejection for these reasons and because the projected proponent, Western Grid Development, LLC is not a PTO and the ISO tariff Section 24.1.2 provides that only PTOs can build and own reliability-driven projects.

ATTACHMENT BB

Weedpatch 70kV Energy Storage Project



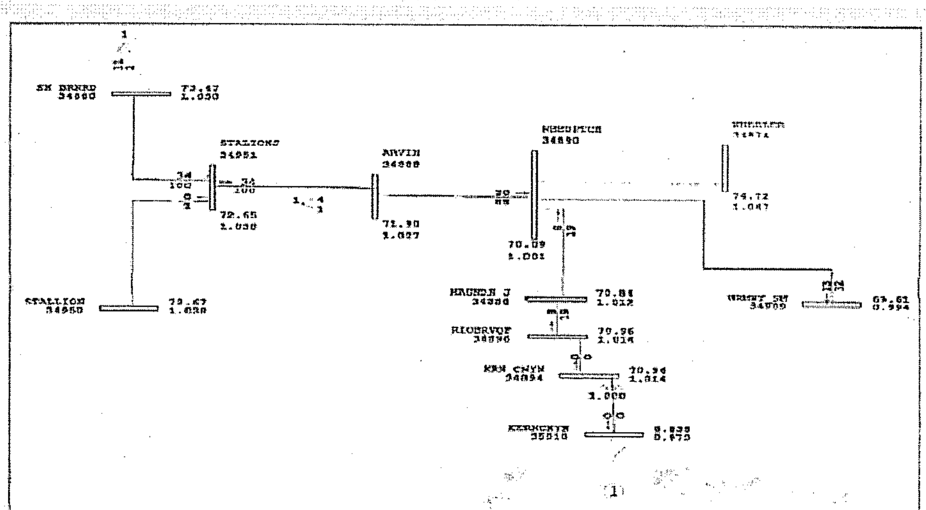


Figure 2: WECC 2014 Post Contingency Weedpatch Flows

Project Proponent: Western Grid Development, LLC

Type of Project: Reliability

Needs: This project responds to a problem that was misidentified in 9/15/09 results. Those results omitted the use of an existing operating procedure.

Project Scope

3 MW battery connected to Weedpatch 70 kV substation

Costs: $4.5 M

Other Considered Alternatives

none

Expected In-Service: 12 / 30 / 2014

Recommended Action: Reject this project.

ATTACHMENT CC

1.1 Public Participation in the Transmission Planning Process

During the 2009 planning cycle, the ISO had the three stakeholder meetings. The initial stakeholder meeting was on March 24, 2009 where the unified planning assumptions were discussed. In October 2009, the ISO held a two-day meeting about the 2010 TP study results posted to the ISO website on September 15, 2009 as well as the reliability projects submitted by the Participating Transmission Owners (PTO) during the 2009 request window. On February 16, 2010 the ISO held its final stakeholder meeting to present and discuss the draft 2010 ISO transmission plan.

1.2 2010 Study Plan and Technical Studies Overview

The 2010 study plan defined the scope and purpose of the studies performed during the 2009 planning cycle. These studies are described in this report as follows:

- Reliability assessment;
- Short-term plan relating to real-time operational studies;
- Greater Bay Area long-term;
- Long-term congestion revenue rights (LT CRR);
- Local capacity requirements (LCR);
- RETI and 33% renewable portfolio standards;
- Congestion study;
- Central California Clean Energy Transmission Project (C3ETP).

1.3 Annual Studies Performed by the ISO

As indicated in the 2010 study plan, the ISO routinely performs a number of technical studies to meet its planning responsibilities and objectives. These technical studies provide the basis for identifying potential physical and economic limitations of the ISO controlled-grid and propose upgrades to maintain or enhance system reliability, promote economic efficiency, and maintain the lifecycle feasibility of long-term congestion revenue rights while also seeking to promote other policy objectives. The results of several key assessments are briefly discussed below.

1.3.1 Reliability Assessment

The system reliability assessment is performed to comply with the applicable NERC standards, (WECC) and ISO requirements. It identifies facilities that do not meet reliability performance requirements during the planning horizons being studied. Mitigation options are proposed by the ISO for each of the identified facilities that do not meet the corresponding performance requirements. The study results from the 2009 planning cycle together with the corresponding ISO proposed solutions are given in Chapters 3 through 5 of this plan.

1.3.2 Short-term Operational Studies

The ISO conducts short-term analysis of its controlled-grid to identify operational gaps that may arise and the operating level at which an operating limit developed to meet reliability standards may be exceeded in real time. Solutions proposed are predominantly limited to projects with lead times of three years or less and are intended to bridge potential gaps that exist between system operations and the traditional grid planning. This is not to say, however, that all short term solutions are confined to a three-year time frame; short-term planning must also consider the potential longer-term solutions to ensure optimal solutions are

Chapter 1: Background and Overview of the 2010 Transmission Plan

The California Independent System Operator Corporation (ISO) is required to assess on an annual basis the reliability of the transmission network under its control (*i.e.,* the ISO controlled-grid). This effort includes identifying the short- term need for grid upgrades and developing a long-term infrastructure vision that incorporates state and federal policy initiatives. The goal, among others, is to maintain compliance with applicable grid reliability criteria, and ensure safe, reliable and sufficient electric service on the ISO controlled-grid.

2008 was a landmark year for conducting ISO transmission planning functions, which included launching a revised Transmission Planning Process (TPP) that satisfies the Federal Energy Regulatory Commission's (FERC) Order No. 890 directives as well as conducting planning studies that provided the basis for the 2010 study plan development with stakeholders. The ISO will use the 2010 Transmission Plan (TP) for documenting the completion of tasks and assessments prescribed by its tariff and the Business Practice Manual for Transmission Planning Process (BPM for TPP) that demonstrates compliance with the North American Reliability Corporation (NERC) reliability standards, Western Electricity Reliability Council (WECC) requirements that are applicable to the ISO as a planning coordinator as well as other ISO reliability requirements. As such, this document contains the planning study results.

The transmission plan (TP) and the associated study plan are named after the year in which the TP is presented to the ISO Board of Governors. Thus, this report, the 2010 ISO Transmission Plan, is for the 2009 planning cycle (PC) and is based on the 2010 study plan. Figure 1-1 depicts the timelines and relationship of the transmission plan, planning cycle, study plan and request window. The request window provides stakeholders with the opportunity to submit alternative projects to ISO proposed solutions for facilities identified in its study as not meeting performance requirements.

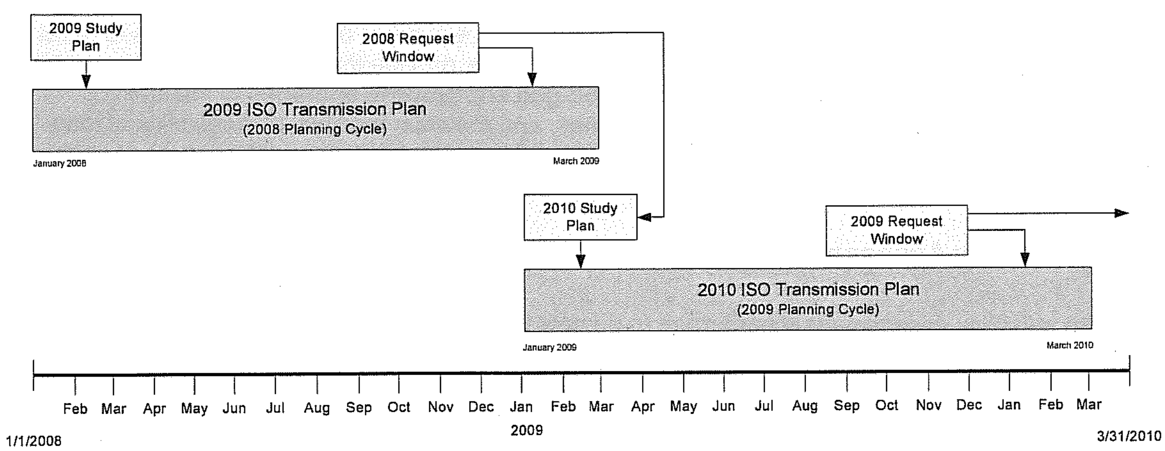


Figure 1-1: Timelines and relationship among the transmission plan, planning cycle, study plan and request window.

ATTACHMENT DD

identified and implemented. Therefore, by definition, an interaction between short and long term planning must exist. The ISO accomplishes this by offsetting the short term planning effort by almost six months from the normal planning cycle schedule. This ensures that the previous year's summer peak can be fully analyzed in preparation for the present year's summer preparedness effort which typically starts near the beginning of the spring season. By the beginning of the summer season, most of the short term work is completed, allowing for longer term proposals developed in the short term planning effort to be considered by the ISO planning engineers as they perform the stage 2 phase planning work.
The short-term planning work that was performed during the 2009 planning cycle is discussed in Section 7.1.

1.3.3 Greater Bay Area Long-Term Study

In accordance with the 2010 study plan, the ISO performed the Greater Bay Area (GBA) long-term study in its 2009 planning cycle. The objectives of the study were two-fold: first, to determine the GBA bulk transmission system reinforcement that may be needed to serve the projected future GBA load; second, to determine load-serving capability of the GBA bulk transmission system under a variety of load and generation dispatch conditions. Further details about the GBA long-term study can be found in Section 7.2.

1.3.4 City of San Francisco System Reliability Analysis

This study[1] was conducted to determine the reliability impact on the San Francisco transmission system for (a) retiring Potrero peaker units #4, #5 and #6, (b) re-cabling Martin-Bayshore-Potrero cables #1 and #2, and (c) adding a new Embarcadero-Potrero 230 kV cable in the system. Further details about the analysis can be found in Section 7.3.

1.3.5 Long-Term Congestion Revenue Rights Study

The ISO performed the long-term congestion revenue rights (LT CRR) study using the base case network topology created for the 2009 CRR annual allocation and auction process. The goal of the study was to ensure that existing fixed long term CRRs allocated and auctioned through the annual CRR allocation and auction process remain feasible for the entire 10-year term, even as new transmission infrastructure is added. The analysis verifies that the 10-year plan as proposed in the 2009 planning cycle does not adversely impact the feasibility of the fixed LT CRRs. Further details about the analysis can be found in Section 7.4.

1.3.6 Local Capacity Requirements

The ISO conducts a short-term local capacity requirements (LCR) technical study to comply with resource adequacy reliability requirements as dictated by Tariff section 40.3.1 and a long-term LCR study in other to advise market participants of future changes to the LCR needs based on load growth, new transmission and new resource additions to the grid. The short-term LCR study serves three basic objectives. First, it provides the minimum local resource needs in order to comply with section 40.3 of the ISO Tariff. Second, provides a basis for allocating to load serving entities (LSEs) thier next year local resource procurement target. Third, it establishes the basis for potential local capacity procurements by the ISO under its Interim Capacity Procurement Mechanism (ICPM) should LSE procurements be deemed insufficient. The LCR studies and the generation deliverability studies are part of the reliability

[1] This study assumed Potrero peaker unit #3 is retired on the basis of the Trans Bay Cable Project being in-service and operating reliably.

requirements initiative that is described in the BPM for Reliability Requirements[2] . Further details about the reliability requirement studies are provided in Section 7.5.

1.3.7 Congestion Study

A congestion evaluation is conducted by relying on past years' (retrospect) grid operation information and forward-looking into future planning horizons. Significant and recurring congestion are identified by synthesis of historical information and forward-looking study results. The congestion retrospect is intended to use one or more years of historical data to summarize grid congestion. However, the implementation of the new ISO locational marginal pricing (LMP) market in 2009 resulted in insufficient data for the one-year minimum data requirement. Consequently, for this year's economic planning study, there is no sufficient information to support the congestion retrospect study. Nevertheless, the data gathered would be incorporated in future studies when one year's worth of the new market and congestion information becomes available.

A congestion forward-looking study is supported by production cost simulations to identify grid congestions in the planning horizon. In this planning cycle, the studied years were 2014 (five-year planning horizon) and 2019 (10-year planning horizon) respectively.

Based on production cost simulations for the years 2014 and 2019, congestion was identified for transmission facilities and closely-related congestion facilities were grouped by areas. The results of the congestion analysis were published as "Economic Planning Study Results." These results can be found at: http://www.caiso.com/272d/272dd52f6db80.pdf. The posted results are preliminary, are subject to further changes and have not been used by the ISO to identify congestion mitigation solutions. The ISO intends to conduct additional congestion studies in the 2010 planning cycle.

[2] The BPM for Reliability Requirements is available on the ISO website at http://www.caiso.com/1840/1840b32523bf0.html

ATTACHMENT EE

This overload occurs for a bus fault at Clayton 115 kV bus 2. ISO is recommending re-rating the line by 2010 to mitigate this overload. For an interim solution, ISO is recommending SPS or RAS incorporated in the operator procedures to drop some calculated amount of load.

Clayton-Pittsburg 115 kV line Overload

This overload is caused by loss of a double circuit tower line carrying Pittsburg-Clayton #3 and #4 115 kV lines. ISO is recommending using SPS by 2010 to drop calculated amount of load to mitigate this overload.

Sobrante-Standard Oil #1 115 kV line Overload

This overload is caused by a bus fault at Sobrante 115kV Section #2. ISO is recommending reconductoring the line by 2010 to mitigate this overload. For an interim solution, ISO is recommending SPS or RAS incorporated in the operator procedures to drop some calculated amount of load.

East Bay Division

TPL 001-System Performance under Normal Conditions

No overloads were found under normal operating conditions (Category A)

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

Oleum-North Tower-Christie 115 kV line Overload

This overload occurs for loss of a Christie-Sobrante 115 kV line and Union CH Generation. ISO is recommending re-rating or reconductoring the line by 2018 to mitigate this overload.

TPL 003-System Performance Following Loss of Two or More BES Elements

Oleum-Martinez 115 kV line Overload

This overload is caused by loss of a double circuit tower line carrying Sobrante G #1 and #2 115 kV. ISO is recommending re-rating or reconductor the line by 2010 to mitigate this overload. For an interim solution, ISO is recommending SPS or RAS incorporated in the operator procedures to drop some calculated amount of load.

3.3.5.5 Key Conclusions

Based on the ISO study assessment, the Greater Bay Area had:

- 1 thermal overload under a normal condition by 2016
- 17 overloads caused by 13 critical single contingencies under summer peak conditions; and
- 66 overloads caused by 60 critical multiple contingencies under summer peak conditions.
- Among the scenarios studied, none produced extreme contingency conditions with potential voltage collapse.

In order to address the identified overloads, the ISO proposed a total of 37 transmission solutions and the request window produced 12 reliability project proposals. Out of these proposals:

- 4 projects are being recommended for approval;

4 projects will be carried forward into the 2010 planning cycle for further analysis
4 projects are recommended for denial.

ISO will coordinate with PG&E regarding an additional 11[5] transmission solutions proposed by ISO.

The four (4) projects, recommended for approval, will carry forward into the 2010 PC and included in the planning assumptions. The remaining ISO proposals will be carried forward into the 2011 TP (*i.e.*, 2010 PC).

The four (4) projects, recommended for denial include one generation project, two transmission projects and one battery storage project. The generation project is Standard Oil Peaker project for which an alternative channel is available to submit this project under LGIP. This is a generation resource project that was proposed in order to solve reliability problems. However, it was not submitted as an alternative to transmission. Although this project directly competes with the San Pablo/Point Pinole 115 kV voltage support project, the ISO's TAC provides for rate recovery of transmission assets, but not generation assets. Accordingly, this project is being recommended for rejection.

One of the transmission projects for denial is a 115 kV series reactor project which according to PG&E is needed in 2019-2020 time frames. ISO considers this a conceptual project too far into the future, and will be reconsidered in the coming years along with alternatives such as re-cabling of the 60 year old Martin - Hunters Point cables. The second transmission project being recommended for denial is a new Embarcadero-Potrero 230 kV cable, which have been determined through the current ISO local capacity requirement (LCR) studies as not needed at least for the next five years, most likely for the next ten years.

Western Grid Development, LLC proposed a battery storage reliability-driven project, the Potrero 115 kV Energy Storage Project, to address apparent capacity shortage in San Francisco in 2011. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control and to recover the costs of the facilities through the ISO's TAC. However, ISO tariff section 24.1.2 provides that PTOS have the obligation to build, own and maintain reliability-driven projects.

The ISO staff considered the proposed battery storage project as an alternative to transmission project to determine whether PG&E should be directed to install battery storage facilities. With a significant reduction in load forecast for San Francisco over the next ten years and planned completion of re-cabling of Martin-Bayshore-Potrero cables #1 and #2 by October 2010 it was determined that no generation at Potrero or additional transmission in San Francisco is needed. Hence, the ISO is recommending for rejection, the Potrero Energy Storage Project.

[5] *Some proposed projects will address multiple overload issues.*

California ISO
Your Link to Power

2010 ISO Transmission Plan Stakeholder Meeting #3

Nisar Shah

Senior Regional Transmission Engineer

Summary of San Francisco results and

Staff Recommendation on the 2010 ISO Transmission Plan Project Proposals

February 16, 2010

3.3.5.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

San Francisco Division

As noted in previous sections of this report, the Trans Bay Cable and Recabling Projects are expected to be placed into service during 2010. Once in place and proven reliable, ISO analysis has concluded that Potrero units 4, 5 and 6 can be released from their RMR agreement. At present, the Trans Bay Cable is anticipated to be placed into service prior to the 2010 summer peak. As demonstrated in past studies, once in place and proven reliable, Potrero Unit 3 will no longer be needed for RMR requirements. As such, these summer peak studies were performed with the Trans Bay Cable in service and Potrero Unit 3 out of service. However, the Recabling Project will not be completed until after the summer peak; as such, Potrero Units 4, 5, and 6 were kept online to ensure service reliability. To address this division's longer term requirements, a more detailed analysis was performed. The results of this analysis are documented in Section 7.3.

TPL 001-System Performance under Normal Conditions

No overloads were found under normal operating conditions

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

Larkin E-Potrero 115 kV circuit #2 overload

This overload is caused by outage of Potrero-Mission 115 kV line during the 2010 summer peak conditions if Potrero units # 4, 5 and 6 are on line and generating at their full capacity of 150 MW. Reducing the output of these units to zero will reduce the flow on the Larkin E-Potrero line to approximately 90% of its emergency rating. Further analysis showed that removing one of the units from service would be sufficient to reduce the loading on the Larkin E-Potrero line to 100% of its emergency rating. Based on these results, the ISO is recommending that generation at Potrero not exceed 100 MW if this contingency occurs.

TPL 003-System Performance Following Loss of Two or More BES Elements

The following ten elements are found overloaded under different L-1-1 conditions for which a common solution is recommended. Overloaded elements are:

- Larkin D-Potrero 115 kV line #1
- Larkin F-Martin C 115 kV line #1
- Mission-Potrero 115 kV line #1
- Larkin E-Potrero 115 kV line #2
- Larkin D-Larkin 1 115/12 kV Transformer #1
- Larkin D-Larkin 2 115/12 kV Transformer #2
- Larkin E-Larkin 1 115/12 kV Transformer #3
- Larkin E-Larkin 2 115/12 kV Transformer #4
- Larkin F-Larkin 1 115/12 kV Transformer #5
- Larkin F-Larkin 2 115/12 kV Transformer #6

The overload levels for these elements range between 127% and 183% for the analysis performed. Additional analysis indicated that these overloads are independent of generation level at Potrero. The ISO is recommending the following mitigation procedure for each of the above overloads:

"Develop an Operating procedure to transfer loads among relevant substations upon detection of an overload and the contingencies that are causing it. If the overload still exists, drop a calculated amount of load either manually or through an SPS. For manual load dropping, short term emergency (STE) ratings must be developed and the line loading must be within STE ratings."

ISO staff is working with PG&E to develop and implement this proposed mitigation procedure before the 2010 summer operating period.

Peninsula Division

TPL 001-System Performance under Normal Conditions

No overloads were found under normal operating conditions.

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

No overloads were found under Category B contingency conditions

TPL 003-System Performance Following Loss of Two or More BES Elements

Belmont-San Mateo 115 kV line #1 overload

This overload is caused by loss of a double circuit tower line, Ravenswood-Bair 115 kV line #1 and #2 at expected load level of summer 2011. Mitigation plan is to re-rate the overloaded line and also develop the Short Term Emergency (STE) rating which is typically good for 30 minutes. If re-rating is not applicable or it does not eliminate overload, then develop operating procedures before summer of 2011 to drop calculated amount of load either manually or through SPS to mitigate overload.

Cooley Landing-Ravenswood E 115 kV line #2 overloading

This overload is caused by loss of a double circuit tower line, Ravenswood-Palo Alto 115 kV line #1 and #2 at expected load level of summer 2010. Mitigation plan is to re-rate the overloaded line and also develop the STE rating. If re-rating is not applicable or it does not eliminate overload, then develop operating procedures before summer of 2010 to drop calculated amount of load either manually or through SPS to mitigate overload.

Palo Alto-Cooley Landing 115 kV line #1 overloading

This overload is caused by loss of a double circuit tower line, Ravenswood-Palo Alto 115 kV line #1 and #2 at expected load level of summer 2010. Mitigation plan is to re-rate the overloaded line and also develop the STE rating. If re-rating is not applicable or it does not eliminate overload, then develop operating procedures before summer of 2010 to drop calculated amount of load either manually or through SPS to mitigate overload.

Palo Alto-Ravenswood E 115 kV line #2 overloading

This overload is caused by loss of two transmission lines on separate towers, Ravenswood-Palo Alto #1 and Cooley Landing-Palo Alto 115 kV lines at expected load level of summer 2010. Mitigation plan is to re-rate the overloaded line and also develop the STE rating. If re-rating is not applicable or it does not recommending SPS or RAS incorporated in the operator procedures to drop some calculated amount of load.

Clayton-kirker tap 115 kV line Overload

This overload occurs for a bus fault at Clayton 115 kV bus 2. ISO is recommending re-rating the line by 2010 to mitigate this overload. For an interim solution, ISO is recommending SPS or RAS incorporated in the operator procedures to drop some calculated amount of load.

Clayton-Pittsburg 115 kV line Overload

This overload is caused by loss of a double circuit tower line carrying Pittsburg-Clayton #3 and #4 115 kV lines. ISO is recommending using SPS by 2010 to drop calculated amount of load to mitigate this overload.

Sobrante-Standard Oil #1 115 kV line Overload

This overload is caused by a bus fault at Sobrante 115kV Section #2. ISO is recommending reconductoring the line by 2010 to mitigate this overload. For an interim solution, ISO is recommending SPS or RAS incorporated in the operator procedures to drop some calculated amount of load.

East Bay Division

TPL 001-System Performance under Normal Conditions

No overloads were found under normal operating conditions (Category A)

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

Oleum-North Tower-Christie 115 kV line Overload

This overload occurs for loss of a Christie-Sobrante 115 kV line and Union CH Generation. ISO is recommending re-rating or reconductoring the line by 2018 to mitigate this overload.

TPL 003-System Performance Following Loss of Two or More BES Elements

Oleum-Martinez 115 kV line Overload

This overload is caused by loss of a double circuit tower line carrying Sobrante G #1 and #2 115 kV. ISO is recommending re-rating or reconductor the line by 2010 to mitigate this overload. For an interim solution, ISO is recommending SPS or RAS incorporated in the operator procedures to drop some calculated amount of load.

3.3.5.5 Key Conclusions

Based on the ISO study assessment, the Greater Bay Area had:

1 thermal overload under a normal condition by 2016
~~47~~ 5 overloads caused by ~~13~~ 5 critical single contingencies under summer peak conditions; and
~~66~~ 76 overloads caused by ~~60~~ 65 critical multiple contingencies under summer peak conditions.

Among the scenarios studied, none produced extreme contingency conditions with potential voltage collapse.

In order to address the identified overloads, the ISO proposed a total of 37 transmission solutions and the request window produced 12 reliability project proposals. Out of these proposals:

4 projects are being recommended for approval;
4 projects will be carried forward into the 2010 planning cycle for further analysis
4 projects are recommended for denial.

ISO will coordinate with PG&E regarding an additional 11[7] transmission solutions proposed by ISO.

The four (4) projects, recommended for approval, will carry forward into the 2010 PC and included in the planning assumptions. The remaining ISO proposals will be carried forward into the 2011 TP (*i.e.*, 2010 PC).

The four (4) projects, recommended for denial include one generation project, two transmission projects and one battery storage project. The generation project is Standard Oil Peaker project for which an alternative channel is available to submit this project under LGIP. This is a generation resource project that was proposed in order to solve reliability problems. However, it was not submitted as an alternative to transmission. Although this project directly competes with the San Pablo/Point Pinole 115 kV voltage support project, the ISO's TAC provides for rate recovery of transmission assets, but not generation assets. Accordingly, this project is being recommended for rejection.

One of the transmission projects for denial is a 115 kV series reactor project which according to PG&E is needed in 2019-2020 time frames. ISO considers this a conceptual project too far into the future, and will be reconsidered in the coming years along with alternatives such as re-cabling of the 60 year old Martin - Hunters Point cables. The second transmission project being recommended for denial is a new Embarcadero-Potrero 230 kV cable, which have been determined through the current ISO local capacity requirement (LCR) studies as not needed at least for the next five years, most likely for the next ten years.

Western Grid Development, LLC proposed a battery storage reliability-driven project, the Potrero 115 kV Energy Storage Project, to address apparent capacity shortage in San Francisco in 2011. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control and to recover the costs of the facilities through the ISO's TAC. However, ISO tariff section 24.1.2 provides that PTOS have the obligation to build, own and maintain reliability-driven projects.

The ISO staff considered the proposed battery storage project as an alternative to transmission project to determine whether PG&E should be directed to install battery storage facilities. With a significant reduction in load forecast for San Francisco over the next ten years and planned completion of re-cabling of Martin-Bayshore-Potrero cables #1 and #2 by October 2010 it was determined that no generation at Potrero or additional transmission in San Francisco is needed. Hence, the ISO is recommending for rejection, the Potrero Energy Storage Project.

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[7] *Some proposed projects will address multiple overload issues.*

Other than the facilities listed in Table 7-2, other facility upgrades as identified in the annual GBA reliability assessment will be required in order to achieve sufficient thermal capability through 2024 under normal, single facility outage and DCTL outage conditions.

In conclusion, based on the analyses performed here, the GBA bulk transmission system does not appear to have an urgent need for a large upgrade for reliability. In terms of the thermal and voltage capabilities, it appears that the GBA bulk transmission system will have sufficient thermal capability to serve the GBA load until about 2024 with some relatively smaller facility upgrades. Whereas, in terms of voltage, the system appears to have sufficient capability to serve the GBA load until about 2019 with approximately 300 MVAR of additional reactive power support. With no new local generation added, the GBA bulk transmission system will need approximately 1000 MVAR of additional reactive support to serve the GBA load until around 2024 satisfying the WECC voltage requirements.

The conclusions drawn here are entirely based on the studies performed for the summer peak loading conditions and the three GBA new generation scenarios. Furthermore, these conclusions are drawn strictly from the reliability planning perspective. Additional studies may be needed to evaluate the GBA bulk transmission upgrade needs from the economic and/or the renewable transmission planning perspectives that will likely be developed in the comprehensive plan for renewables integration. In that regard, the ISO's economic planning study for GBA has identified congestion on some GBA bulk transmission facilities predominantly during off-peak loading and high wind dispatch scenario associated with the Solano competitive renewable energy zone (CREZ). The base case used for this economic study was targeted to meet the 33% renewable portfolio standard (RPS) and hence was modeled with a high concentration of wind generation (about 1000 MW) in Solano area.

Details of this study and the economic s planning study will be published in the ISO website.

7.3 Reliability Analysis for the City of San Francisco

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7.3.1 Summary

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Since the retirement of the Hunters Point Power facility, a great deal of focus has been placed on developing a transmission plan that would result in the retirement of all generation at the Potrero Power Plant facility. Over the past several years, a great deal of work has been done to complete the installation of the Trans Bay Cable Project that, once in service, will transfer up to 400 MW of electricity from the Pittsburg area to the San Francisco area. Past studies performed by the ISO had determined that once the Trans Bay Cable Project was placed into service and proven reliable, it would provide enough electrical capacity into the San Francisco area to eliminate the RMR requirement for Potrero Unit 3. However, lacking other transmission infrastructure improvements within San Francisco, the need for Potrero Units 4, 5, and 6 remained.

Past studies for San Francisco had indicated that approximately 150 MW of generation would be needed in the City to ensure system reliability while allowing for an expected load growth of about 1% (~10 MW) per year. However, since the ISO conducted its earlier analysis, two key assumptions used in that earlier analysis were modified:

1. PG&E adjusted ten-year load forecast was reduced to 0.6%/year as compared to their historical projection of 1%/year;

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2. PG&E provided updated new cable ratings for their recabling project (Martin-BayShore-Potrero #1 and #2) that were significantly higher than the prior ratings established for this project.

ISO reviewed these modifications provided by PG&E and found them reasonable. After adjusting for the above assumptions and assuming Trans Bay Cable is in service and proven reliable and the recabling project completed, the study revealed that Potrero Units 4, 5, and 6 can be released from their RMR designation. Further, analysis of PG&E's Embarcadero - Potrero 230 kV cable was also performed, which shows that this cable is not needed within the ten year planning horizon covered by the Transmission Plan. This project can be re-evaluated at a later time should any significant changes in the planning assumptions occur.

7.3.2 Key Assumptions

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- Study years: 2010, 2014, 2019 and selected future years

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- Extreme weather forecast (1 in 10) for SF and Peninsula
- Updated Cable ratings in SF provided by PG&E
- TransBay Cable (TBC) in service
- Potrero Unit 3 out of service
- Potrero Units 4, 5, and 6 in service

Scenarios Evaluated:

- Martin-Bayshore-Potrero re-cabling (2010 study)

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No Generation at Potrero

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150 MW Generation at Potrero

- With and Without new Embarcadero-Potrero 230 kV cable (2014, 2019)

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Contingencies:

For the San Francisco and Peninsula areas, all 60 kV to 230 kV facilities were taken out of service, one at a time for Category B, and N-1-1, bus faults, and double circuit tower line outages for Category C. To meet ISO planning standard for Category B, selected generator and line outages (G-1, L-1) were also evaluated.

7.3.3 Results

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a. Martin-Bayshore-Potrero re-cabling:

A single line diagram of San Francisco's transmission system is shown in Figure 7.1. The Martin-Bayshore-Potrero cables #1 and #2, identified as AHW-1 and AHW-2 respectively in Figure 7.1, are more than 50 years old and are currently undergoing re-cabling with higher capacity cables. AHW-2 is currently out of service and is scheduled to be back in service after re-cabling by April 2010. AHW-1 will then be taken out of service for re-cabling and it will be back in service by November 2010. Completion of AHW-2 is on schedule.

By the summer of 2010, it is expected that AHW-2 will be in service with higher ratings and AHW-1 will be out of service for recabling. The TBC will be in service. Potrero Units 4, 5, and 6 are assumed off line.

Field Code Changed

Fig 7.1 San Francisco One-Line diagram

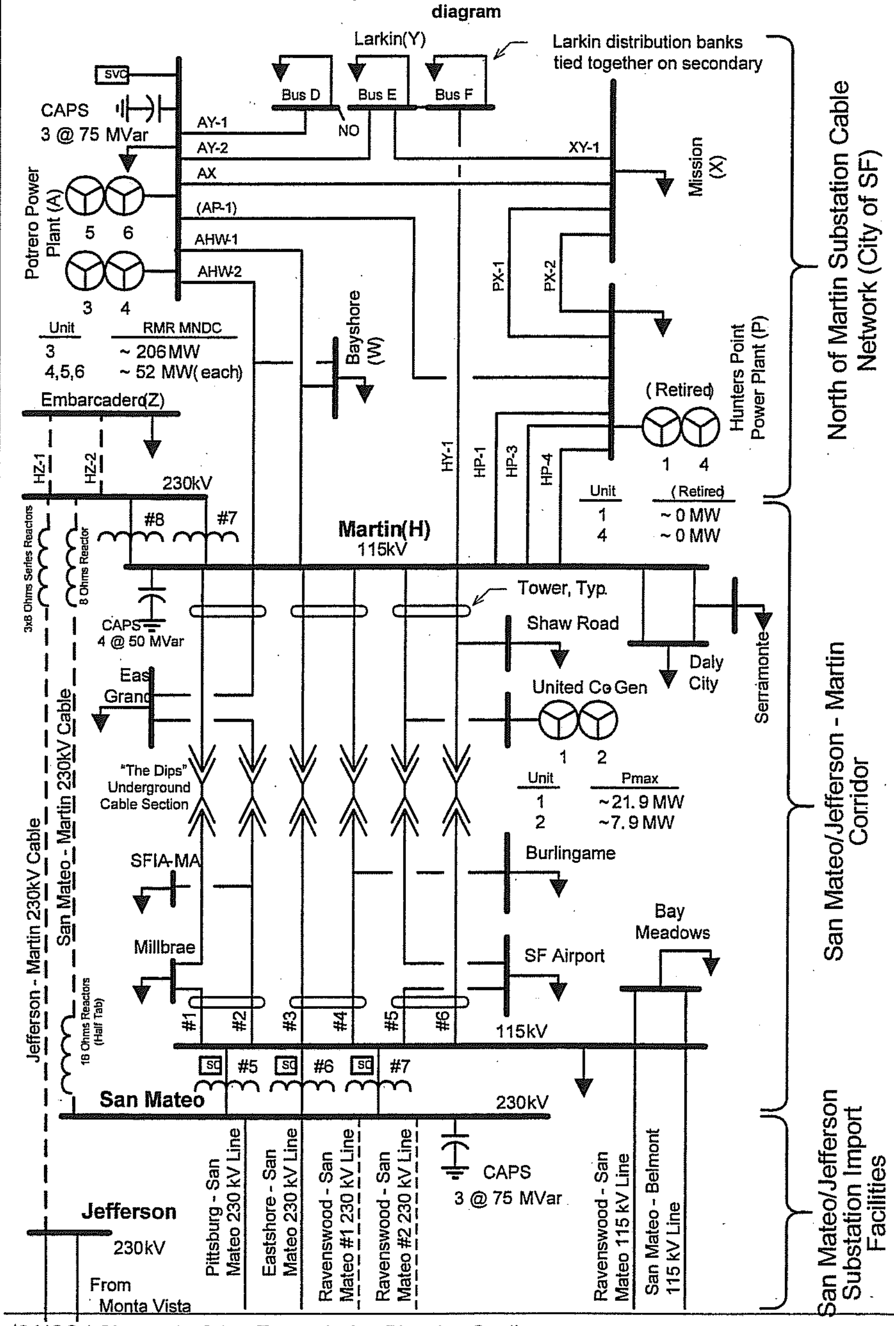

Table 7.3 shows the results of Category B outages for this scenario. The results show that no transmission facilities in San Francisco will be overloaded under Category B contingency conditions. All facilities remain within their applicable ratings. It should be noted that Mission-Potrero 115 kV circuit is loaded to 99.4% of its emergency rating. Should an overload occur, the proposed DC runback mitigation scheme placed into service with the Trans Bay Cable will be implemented to ramp down the output of Trans Bay Cable from 400 MW to 300 MW to relieve this overload.

Table 7.4 shows Category C results for the condition when AHW-1 is out for re-cabling, TBC is in service and Potrero units 4, 5, and 6 are off line. For this condition, significant overloading of transmission facilities in San Francisco will occur which will require load dropping within the City to address these overloads. Further analysis demonstrated that these overloads were largely independent of generation at Potrero; as such, load shedding will be needed.

Table 7.5 shows Category C results with Potrero units 4, 5 and 6 online and generating at full 150 MW. All other assumptions remain the same. These results show that only Martin-Hunters Point 115 kV lines #1 and #3 will no longer be overloaded. All other facilities will remain overloaded for Category C outages. These results show that Potrero Units 4, 5, 6 have negligible impact on addressing Category C outages, as such, the ISO has determined these units could be released from their RMR obligations under this scenario .

Table 7.3

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2010 Heavy Summer--Martin-Bayshore-Potrero #1 out
Trans Bay Cable In; Potrero Unit 3 Out; Potrero Units 4, 5, and 6 Out

Category B Outages

Facility					Worst Contingency	2010 LOADING
MISSON	115	POTRERO	115	#1	Potrero-Larkin E 115 kV line	99.4%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission 115 kV line	86.1%
LARKIN F	115	LARKIN 2	12	#6	Potrero-Larkin D 115 kV line	85.9%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission 115 kV line	85.4%
LARKIN E	115	LARKIN 2	12	#4	Martin C-Larkin F 115 kV line	83.4%
LARKIN F	115	LARKIN 1	12	#5	Potrero-Larkin D 115 kV line	82.8%
LARKIN E	115	LARKIN 1	12	#3	Martin C-Larkin F 115 kV line	82.1%
MARTIN C	115	HNTRS PT	115	#3	Trans Bay Cable	81.9%
MARTIN C	115	HNTRS PT	115	#1	Trans Bay Cable	81.3%
LARKIN D	115	LARKIN 2	12	#2	Martin C-Larkin F 115 kV line	81.2%
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission 115 kV line	80.6%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D 115 kV line	78.5%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission 115 kV line	77.3%
MARTIN C	115	BAYSHOR2	115	#2	Trans Bay Cable	76.7%
BAYSHOR2	115	POTRERO	115	#2	Trans Bay Cable	71.0%

Table 7.4

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2010 Heavy Summer--Martin-Bayshore-Potrero #1 out
Trans Bay Cable In; Potrero Unit 3 Out; Potrero Units 4, 5, and 6 Out

Category C Outages

Facility					Worst Contingency	2010 LOADING
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission and Larkin F-Martin 115 kV	171.5%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission and Potrero-Hunters point 115 kV	102.2%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission and Potrero-Larkin D 115 kV	170.0%
MARTIN C	115	HNTRS PT	115	#3	TransBay Cable and Martin-Hunters Point #1 115 kV	114.7%
MARTIN C	115	HNTRS PT	115	#1	TransBay Cable and Martin-Hunters Point #3 115 kV	111.4%
MISSON	115	POTRERO	115	#1	Potrero-Larkin D and Potrero-Larkin E 115 kV	123.6%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission and Larkin F-Martin 115 kV	175.2%
LARKIN D	115	LARKIN 2	12	#2	Larkin E-Mission and Larkin F-Martin 115 kV	176.1%
LARKIN E	115	LARKIN 1	12	#3	Potrero-Larkin D and Larkin F-Martin 115 kV	175.6%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D and Larkin F-Martin 115 kV	175.2%
LARKIN F	115	LARKIN 1	12	#5	Larkin E-Mission and Potrero-Larkin D 115 kV	176.4%
LARKIN F	115	LARKIN 2	12	#6	Larkin E-Mission and Potrero-Larkin D 115 kV	173.9%

Table 7.5

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2010 Heavy Summer--Martin-Bayshore-Potrero #1 out
Trans Bay Cable In; Potrero Unit 3 Out; Potrero Units 4, 5, and 6 In

Category C outages

Facility					Worst Contingency	2010 LOADING
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission and Larkin F-Martin 115 kV	171.5%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission and Potrero-Larkin D 115 kV	169.9%
MISSON	115	POTRERO	115	#1	Potrero-Larkin D and Potrero-Larkin E 115 kV	144.2%
POTRERO	115	LARKIN E	115	#2	Potrero-Mission and Potrero-Hunters point 115 kV	143.0%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission and Larkin F-Martin 115 kV	175.2%
LARKIN D	115	LARKIN 2	12	#2	Larkin E-Mission and Larkin F-Martin 115 kV	176.1%
LARKIN E	115	LARKIN 1	12	#3	Potrero-Larkin D and Larkin F-Martin 115 kV	175.6%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D and Larkin F-Martin 115 kV	175.2%
LARKIN F	115	LARKIN 1	12	#5	Larkin E-Mission and Potrero-Larkin D 115 kV	176.4%
LARKIN F	115	LARKIN 2	12	#6	Larkin E-Mission and Potrero-Larkin D 115 kV	173.9%

b. With and Without new Embarcadero-Potrero 230 kV cable

A single line diagram showing the proposed 230 kV cable (highlighted) from Embarcadero 230 kV substation to Potrero 115 kV substation with a 230/115 kV transformer at Potrero substation is shown in Figure 7.2 below. The stated purpose of this project was to increase the load serving capability of San Francisco and enhance reliability of the San Francisco electric system, in particular the Embarcadero load center. This project was evaluated in the five and ten year planning horizon of 2014 and 2019.

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Figure 7.2

Embarcadero-Potrero 230 kV Cable

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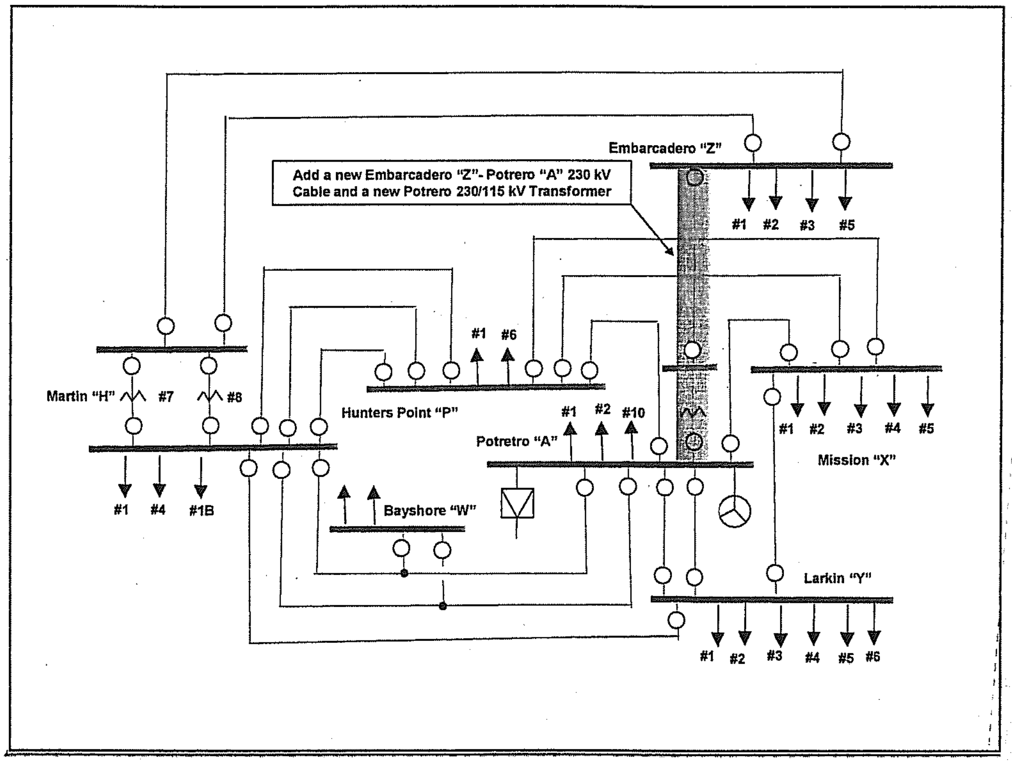

The Embarcadero substation is currently served by Martin substation through two 230 kV underground cables between Martin and Embarcadero. The loss of both cables will result in loss of approximately 95% (260 MW) of Embarcadero substation load. The remaining 5% would continue to be served through the 12 kV distribution system. Analysis has shown that all of the Embarcadero substation load can be served by restoring one of the Martin – Embarcadero 230 kV circuits to service. Analysis also shows that the proposed Embarcadero – Potrero 230kV line will prevent loss of Embarcadero substation load should both Martin – Embarcadero 230kV circuits be lost. However, from the perspective of NERC and WECC Planning standards, loss of two circuits constitutes a Category C contingency for which load dropping is allowed.

Table 7.6 below shows the San Francisco transmission system performance under Category B outages for no generation at Potrero and no new Embarcadero-Potrero cable. Loading of facilities in 2014 and 2019 is identified. Only one circuit, Mission-Potrero 115 kV line, is slightly overloaded. As mentioned earlier, this overload can be mitigated through a DC runback scheme on the Trans Bay Cable. All other facilities are well within their applicable ratings. The next heavily loaded line is at 90% level increasing only at a rate of about 1% in five years. This table indicates that San Francisco transmission system, without the new Embarcadero-Potrero cable, is quite robust and will serve the City's electric demand well beyond 2019 under all possible Category B contingencies.

Table 7.6

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No generation at Potrero; No Embarcadero-Potrero 230 kV Cable
Trans Bay Cable In; Recabling Project Complete

Category B outages

Facility					Worst Contingency	LOADING	
						2014	2019
MISSON	115	POTRERO	115	#1	Potrero-Larkin E 115 kV line	102.2%	103.2%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission 115 kV line	89.6%	90.4%
LARKIN F	115	LARKIN 2	12	#6	Potrero-Larkin D 115 kV line	87.1%	88.6%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission 115 kV line	86.7%	88.2%
LARKIN E	115	LARKIN 2	12	#4	Martin C-Larkin F 115 kV line	84.5%	86.0%
LARKIN F	115	LARKIN 1	12	#5	Potrero-Larkin D 115 kV line	83.9%	85.4%
LARKIN E	115	LARKIN 1	12	#3	Martin C-Larkin F 115 kV line	83.2%	84.7%
LARKIN D	115	LARKIN 2	12	#2	Martin C-Larkin F 115 kV line	82.4%	83.8%
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission 115 kV line	81.9%	83.3%

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Table 7.7 below shows the results for San Francisco transmission system under Category C outages. Among more than 100 Category C outages evaluated, these are the most severe L-1-1 contingencies causing overloads. Most of the transmission facilities including transformers are severely overloaded and can be mitigated through transferring loads to other substations and some load dropping. ISO staff is working with PG&E staff to finalize mitigation plans before the summer of 2010.

Table 7.7

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No generation at Potrero; No Embarcadero-Potrero 230 kV Cable
Trans Bay Cable In; Recabling Project Complete

Category C outages

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Facility					Worst Contingency	LOADING	
						2014	2019
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission and Larkin F-Martin 115 kV	174.5%	178.0%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission and Potrero-Larkin D 115 kV	173.3%	177.0%
MISSON	115	POTRERO	115	#1	Potrero-Larkin D and Potrero-Larkin E 115 kV	124.7%	126.1%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission and Potrero-Hunters point 115 kV	102.1%	102.7%
LARKIN F	115	LARKIN 1	12	#5	Larkin E-Mission and Potrero-Larkin D 115 kV	179.4%	183.1%
LARKIN D	115	LARKIN 2	12	#2	Larkin E-Mission and Larkin F-Martin 115 kV	179.0%	182.5%
LARKIN E	115	LARKIN 1	12	#3	Potrero-Larkin D and Larkin F-Martin 115 kV	178.5%	182.0%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission and Larkin F-Martin 115 kV	178.0%	181.5%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D and Larkin F-Martin 115 kV	178.0%	181.5%
LARKIN F	115	LARKIN 2	12	#6	Larkin E-Mission and Potrero-Larkin D 115 kV	176.8%	180.2%

Tables 7.8 and 7.9 below show the results for San Francisco transmission system for Category B and Category C outages with new Embarcadero-Potrero 230 kV cable in service. The results are very similar to those shown in Tables 7.6 and 7.7. Mission-Potrero overload in Table 7.8 is slightly higher than it is in Table 7.6, however, it can be mitigated through the DC runback scheme.
Comparing the results of without and with Embarcadero-Potrero cable, it appears that Embarcadero-Potrero cable provides no technical benefit to the system in terms of either eliminating some overloads, or reducing overload levels.

The bus voltages in San Francisco under all Category B and Category C outages are satisfactory and within the allowable NERC and WECC voltage criteria.

Table 7.8

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No generation at Potrero; Embarcadero-Potrero 230 kV Cable added
Trans Bay Cable In; Recabling Project Complete

Category B outages

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Facility					Worst Contingency	LOADING	
						2014	2019
MISSON	115	POTRERO	115	#1	Potrero-Larkin E 115 kV line	105.9%	107.0%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission 115 kV line	93.5%	94.3%
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission 115 kV line	82.2%	83.6%
LARKIN F	115	LARKIN 2	12	#6	Potrero-Larkin D 115 kV line	87.1%	88.6%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission 115 kV line	87.0%	88.5%
LARKIN E	115	LARKIN 2	12	#4	Martin C-Larkin F 115 kV line	84.5%	85.9%
LARKIN F	115	LARKIN 1	12	#5	Potrero-Larkin D 115 kV line	83.9%	85.4%
LARKIN E	115	LARKIN 1	12	#3	Martin C-Larkin F 115 kV line	83.2%	84.6%
LARKIN D	115	LARKIN 2	12	#2	Martin C-Larkin F 115 kV line	82.5%	83.9%

Table 7.9

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No generation at Potrero; Embarcadero-Potrero 230 kV Cable added
Trans Bay Cable In; Recabling Project Complete

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Category C outages

Facility					Worst Contingency	LOADING	
						2014	2019
LARKIN D	115	POTRERO	115	#1	Larkin E-Mission and Larkin F-Martin 115 kV	174.5%	178.0%
LARKIN F	115	MARTIN C	115	#1	Larkin E-Mission and Potrero-Larkin D 115 kV	173.3%	177.0%
MISSON	115	POTRERO	115	#1	Potrero-Larkin D and Potrero-Larkin E 115 kV	128.1%	129.6%
LARKIN E	115	POTRERO	115	#2	Potrero-Mission and Potrero-Hunters point 115 kV	107.7%	108.4%
LARKIN F	115	LARKIN 1	12	#5	Larkin E-Mission and Potrero-Larkin D 115 kV	179.4%	183.1%
LARKIN D	115	LARKIN 2	12	#2	Larkin E-Mission and Larkin F-Martin 115 kV	179.0%	182.5%
LARKIN E	115	LARKIN 1	12	#3	Potrero-Larkin D and Larkin F-Martin 115 kV	178.5%	182.0%
LARKIN E	115	LARKIN 2	12	#4	Potrero-Larkin D and Larkin F-Martin 115 kV	178.0%	181.5%
LARKIN D	115	LARKIN 1	12	#1	Larkin E-Mission and Larkin F-Martin 115 kV	178.0%	181.5%
LARKIN F	115	LARKIN 2	12	#6	Larkin E-Mission and Potrero-Larkin D 115 kV	176.8%	180.2%

7.3.4 Conclusions

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- Provided the Trans Bay Cable is proven to be reliable and the recabling of the Martin – Bayshore – Potrero lines 1 and 2 are completed in 2010, Potrero Units 3, 4, 5, and 6 can be released from their RMR agreements for 2011 and beyond;

- Provided the Trans Bay Cable is proven to be reliable and the recabling of the Martin – Bayshore – Potrero lines 1 and 2 are complete, a new Embarcadero – Potrero 230kV cable is not needed over the 10-year planning horizon;

- A DC runback scheme for the Trans Bay Cable will be required to address an overload of the Mission-Potrero 115kV cable for the loss of the Potrero-Larken E 115kV cable. A runback scheme has been installed as part of the Trans Bay Cable Project;

- Some 115 kV cables and 115/12 kV transformers are found overloaded under Category C contingency conditions for which a mitigation plan will be finalized with PG&E before the summer of 2010;

- Voltages in San Francisco remain within the allowable NERC/WECC criteria for all Category B and Category C contingencies through 2019;

- If both existing Martin-Embarcadero 230 kV cables trip, about 95% of the Embarcadero load (260 MW) will automatically drop. This entire load can be restored by bringing at least one cable back in service.

ATTACHMENT FF

Summary of San Francisco Reliability Assessment Results

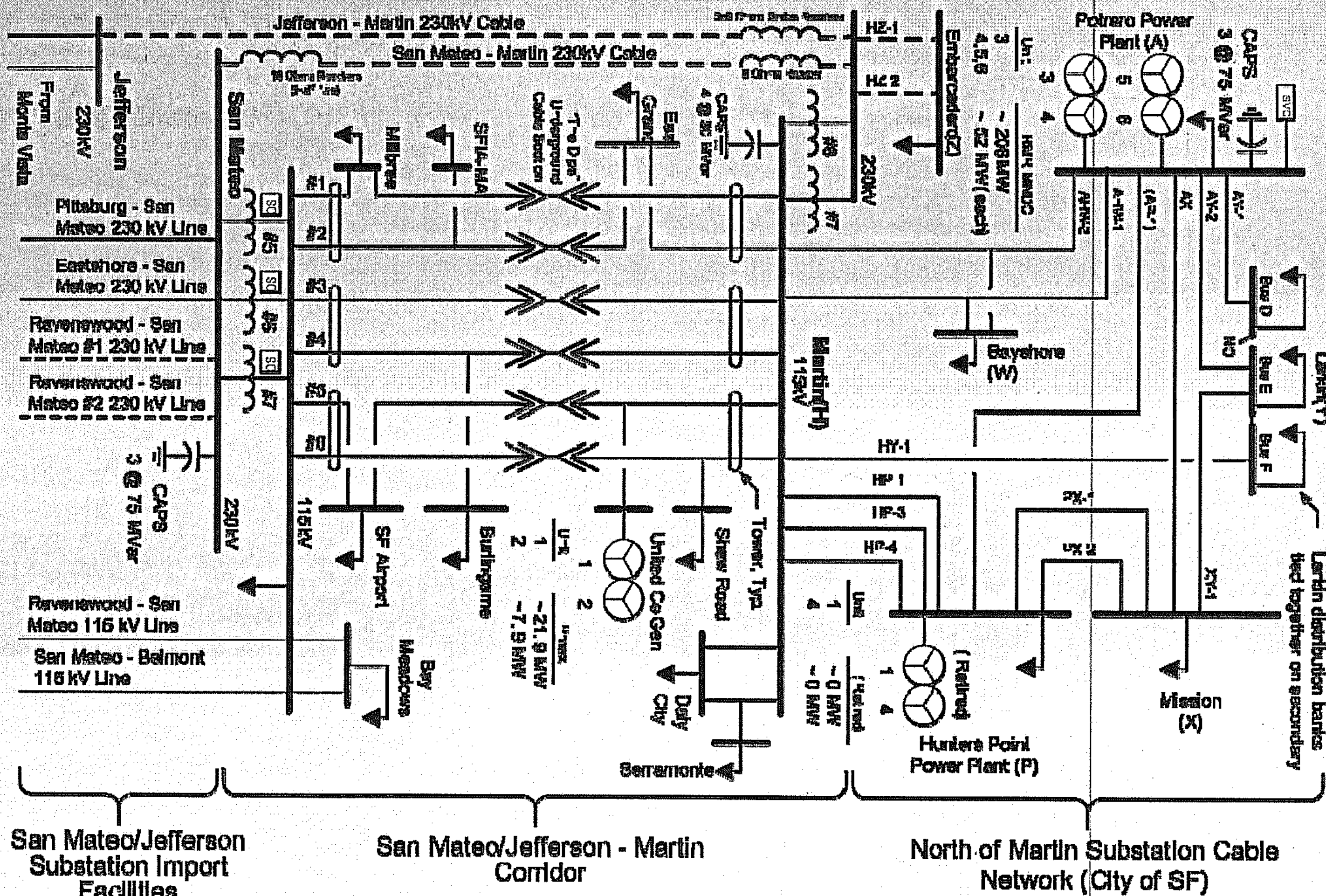
Key Assumptions:

- Study years: 2010, 2014, 2019 and selected future years
- Extreme weather forecast (1 in 10) for SF and Peninsula
- Updated Cable ratings in SF provided by PG&E
- TransBay Cable (TBC) in service

Scenarios Evaluated:

- Martin-Bayshore-Potrero re-cabling (2010 study)
- No Generation at Potrero
- 150 MW Generation at Potrero
- With and Without new Embarcadero-Potrero 230 kV cable

San Francisco One-line diagram



California ISO
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Key Findings

- San Francisco load can be reliably served for the next ten year planning horizon without Potrero generation and without Embarcadero-Potrero 230 kV cable.
- Mission-Potrero and Larkin-Potrero115 kV cables are found overloaded under Category B contingency conditions for which mitigation plans are proposed.
- Some 115 kV cables and 115/12 kV transformers are found overloaded under Category C contingency conditions for which mitigation plan is proposed.
- Voltages in San Francisco remain within the allowable NERC/WECC criteria for all Category B and Category C contingencies through 2019.
- If both existing Martin-Embarcadero 230 kV cables trip, about 95% of the Embarcadero load (260 MW) will automatically drop. This entire load can be restored by bringing at least one cable back in service.
- Study results are highly dependent upon the load forecast provided by PG&E as well as achieving higher ratings on its current re-cabling projects. If load forecast is higher than assumed, studies need to be revisited. The ISO will conduct annual studies with updated load forecast to refresh these studies.

ISO Proposed Mitigation of overloads

Category B overloads:

1. Mission-Potrero overload can be mitigated through existing planned DC run-back scheme which requires ramping down TBC output from 400 MW to 300 MW.
2. Larkin-Potrero overload is due to excessive generation at Potrero and can be mitigated by dropping one Potrero unit. Note: Since Potrero units will not be in service after 2010, this overload will not occur.

Category C overloads:

All category C overloads in San Francisco are caused by N-1-1 contingencies and are due to heavy loads at substations. These overloads can not be mitigated through generation at Potrero. The proposed mitigation is to develop an operating procedure to transfer loads among substations and if overload still exists, drop load either manually or through SPS.

Overview of 2009 Request Window
San Francisco and Peninsula area

The ISO received 2 reliability projects through the RW and one ongoing project from the 2008 RW has been finalized and included in this list.

- Recommended for Approval – 0 Projects
- Of the 0 projects recommended for approval, 0 projects are over $50M and are therefore being recommended for CAISO Board approval
- Denied – 3 Projects
- ISO will Coordinate with PG&E on Final Project Proposals – 0 Projects

ISO Recommendations on Proposed Projects in San Francisco and Peninsula area

Project Name	Type of Project	Project Sponsor	Cost of Project	ISO Recommendation
SF 115 kV Series Reactors	Reliability	PG&E	$5M-$10M	Reject
Potrero 115 kV Energy Storage Project	Reliability	Western Grid Dev. LLC	$30 M	Reject
Embarcadero-Potrero 230 kV Transmission	Reliability	PG&E	$130 M-$150 M	Reject

Denied Projects

California ISO
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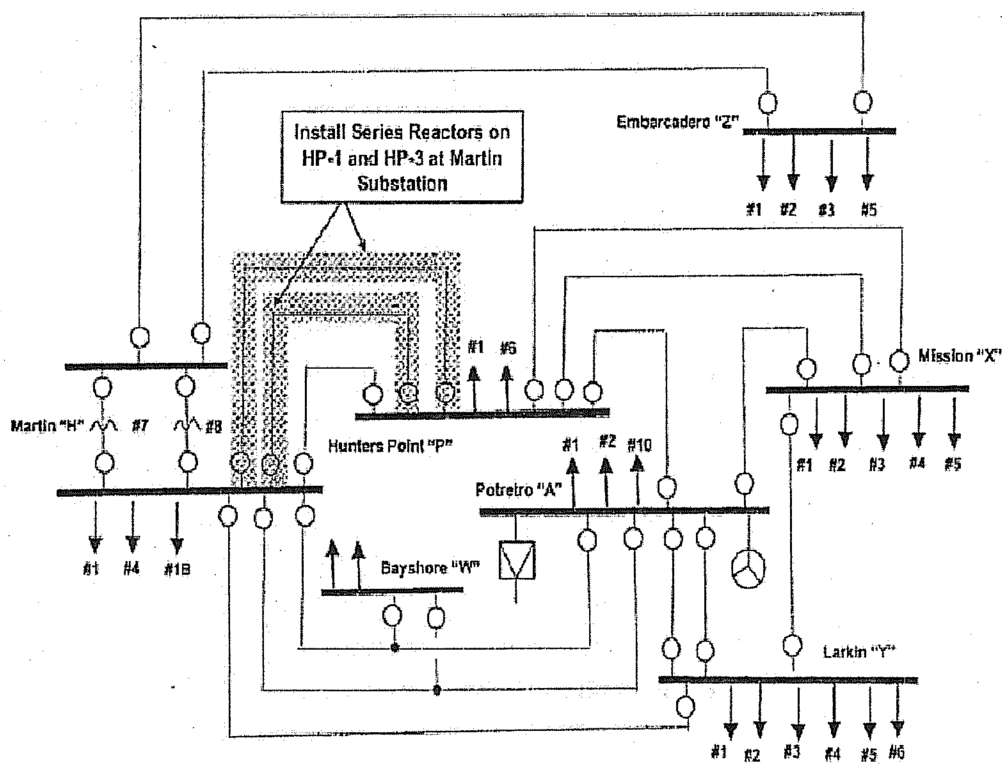
SF 115 kV Series Reactors



Project Proponent: PG&E

Type of Project: Reliability

Needs (stated by the proposer): NERC Category C overloads (2019)

Project Scope

- At Martin substation install 0.3 ohm series reactors on each HP-1 and HP-3 cables along with protective devices

Costs: $5M-$10M

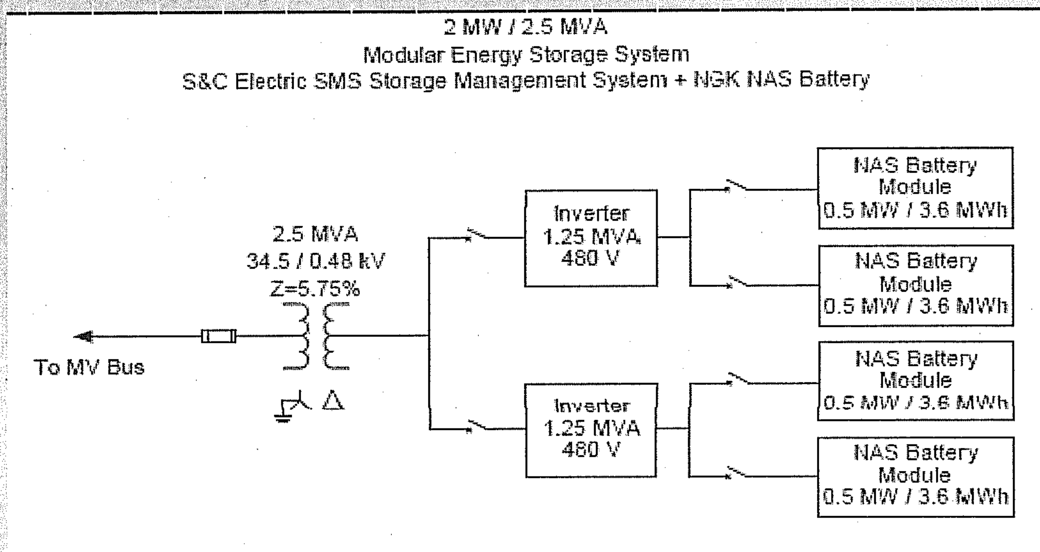
Other Considered Alternatives

None

Expected In-Service: December 31, 2019

Recommended Action: Reject this project for the following reasons: 1) ISO did not identify need for this project, 2) PG&E identified need 10 years from today, 3) Load dropping for Category C is a cheaper alternative, 4) Re-cabling of HP-1 and HP-3 is overdue, and is also a better alternative

Potrero 115 kV Energy Storage Project



Project Proponent: Western Grid Development, LLC

Type of Project: Reliability

Needs (stated by the proposer): To meet LCR requirement in San Francisco in 2011

Project Scope

- Install 20 MW of Battery storage at Potrero substation

Costs:

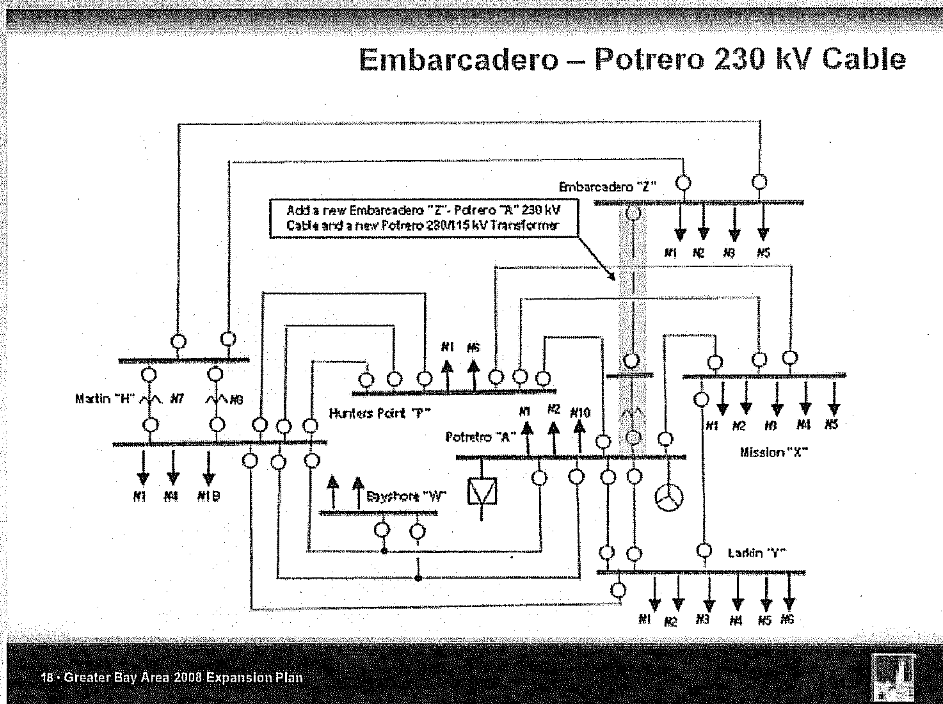
Other Considered Alternatives

None

Expected In-Service: December 30, 2010

Recommended Action: Reject this project because: 1) proposal is based on obsolete LCR study, 2) After re-cabling of AHW-1 and AHW-2, the updated study indicates no need for new generation in San Francisco in 2011.

Embarcadero-Potrero 230 kV Transmission



Project Proponent: PG&E

Type of Project: Reliability

Needs (stated by the proposer): Reliability—NERC compliance and Operational Flexibility, increase load serving capability of San Francisco

Project Scope

- Install a new 230 kV cable between Embarcadero and Potrero substations (about 3 miles) and a 230/115 kV transformer at Potrero

Costs: $130M--$150M

Other Considered Alternatives

None

Expected In-Service: May 31, 2012

Recommended Action: Reject this project because :1) With TBC coming in service in Spring 2010 and recabling of AHW-1 & AHW-2 by end of 2010, ISO studies indicated no need for new generation or transmission in San Francisco for **at least** until 2019, 2) load dropping is a much cheaper option to satisfy NERC requirement for Category C outages

ATTACHMENT GG

December 21, 2010

__Via Federal Express & E-mail Delivery__

Mr. John Chillemi
President
GenOn California North, LLC
696 W. 10th Street, P.O. Box 192
Pittsburg, CA 94565

Re: Notice of Termination of Reliability-Must Run Agreement effective January 1, 2011

Dear Mr. Chillemi:

The California Independent System Operator Corporation hereby provides notice of termination, effective January 1, 2011, pursuant to section 2.2(f) of the Reliability Must-Run Agreement between the ISO and GenOn Potrero.

The ISO understands that the notice of termination is contingent upon Federal Energy Regulatory Commission (FERC) acceptance of GenOn Potrero's November 30, 2010 filing proposing amendments to the agreement, including the addition of section 2.2(f), that would permit the ISO to terminate the agreement prior to the end of a contract year. FERC action in response to GenOn Potrero's filing is expected by January 31, 2011. With FERC acceptance without modification, the agreement will terminate as of midnight on February 28, 2011.

The ISO appreciates the reliability service that the GenOn Potrero units have provided over the years and appreciates GenOn Potrero's spirit of cooperation in negotiating the amendments to the agreement that provide for early termination.

The Potrero units have played a critical role in meeting San Francisco's local energy requirements and in satisfying San Francisco local reliability standards. With the Trans Bay cable and local transmission upgrade projects in commercial operation, the time has now come when the GenOn Potrero units are not longer needed for reliability service.

Sincerely,

Steve Berberich
Vice President and Chief Operating Officer

SB/smd

cc: Mayor Gavin Newsom
David Reich (GenOn Americas, Inc.)
Laurence Chaset (CPUC)
Sidney Davies (ISO)
Debra Raggio (GenOn Americas, Inc.)
Laura Douglas (PG&E)
Ed Harrington (SFPUC)
Gil Grotta (ISO)

ATTACHMENT HH

CVLY-T-039	Brighton-Davis 115 kV	Brighton-W. Sacramento 115 kV and Woodland #1	B	100.3%	112.6%	
		Davis-Woodland 115 kV and Brighton-W. Sacramento 115 kV	C3	159.4%	192.4%	
		DCTL Rio Oso-W. Sacramento 115 kV and W. Sacramento-Brighton 115 kV	C5	132.8%	151.9%	
		Davis-Woodland 115 kV and Brighton-W. Sacramento 115 kV	C3	158.0%	190.9%	
		DCTL Rio Oso-W. Sacramento 115 kV and W. Sacramento-Brighton 115 kV	C5	131.4%	150.5%	
		Davis-Woodland 115 kV and Brighton-W. Sacramento 115 kV	C3	158.0%	190.9%	
		DCTL Rio Oso-W. Sacramento 115 kV and W. Sacramento-Brighton 115 kV	C5	131.4%	150.5%	
CVLY-T-040	West Sacramento-Brighton 115 kV	Woodland-Davis 115 kV and Brigton-Davis 115 kV	C3	<100%	106.0%	
CVLY-T-041	Madison-Vaca 115 kV	N/A	A	100.1%	105.4%	Reconductor
CVLY-T-042	Vaca-Suisun-Jameson 115 kV	Vaca-Suisun 115 kV and City Fair #1	B	<100%	105.8%	Reconductor
		Vaca-Vacaville-Jameson-North Tower 115 kV and Vaca-Suisun 115 kV	C3	138.7%	152.6%	SPS
CVLY-T-043	Vaca Dixon # 3 230/115 kV	Vaca Dixon # 2&2A and # 4 230/115 kV	C3	<100%	101%	Add new 230/115 kV Bank or new 230/115 kV station
CVLY-T-044	Vaca Dixon # 4 230/115 kV	Vaca Dixon # 2&2A and # 3 230/115 kV	C3	<100%	101%	
CVLY-T-045	Vaca Dixon # 2&2A 230/115 kV	Vaca Dixon # 3 and # 4 230/115 kV	C3	148%	157%	Replace Vaca Dixon #2&2A 230/115 kV
				175%	185%	
				177.7%	190.7%	
CVLY-T-046	Vaca Dixon # 5 115/60 kV	Vaca-Dixon #9 115/60 kV	B	109%	111%	Replace Vaca Dixon #5 115/60 kV or upgrade Dixon to 115/230 kV
		Vaca Dixon-Dixon #1 60 kV and Vaca-Dixon #9 115/60 kV	C3	110%	113%	
CVLY-T-047	Cortina 230/115/60 kV	Cortina-Dunnigan 60 kV and Wadham #1	B	110%	119%	New Cortina or Colusa 230/60 kV
		Wadham #1	B	106%	114%	
CVLY-T-048	Cortina # 2 60 kV	Cortina # 160 kV	B	118.5%	132.8%	Change/Disable automatics or reconductor
		CPV-Cortina 230 kV and Cortina # 1 60 kV	C3	119.4%	137.7%	
		Cortina # 160 kV	B	118.5%	132.9%	
		CPV-Cortina 230 kV and Cortina # 1 60 kV	C3	119.5%	137.8%	
CVLY-T-049	Cortina # 3 60 kV	Cortina # 4 60 kV and Wadham #1	B	112.2%	118.7%	Change/Disable automatics or reconductor
CVLY-T-050		Stagg-Tesla 230 kV and Eight Mile-Tesla 230 kV	C3	N/A	Diverge	Stagg 230 kV area reinforcement
CVLY-T-051		Stagg-Tesla 230 kV and Eight Mile-Tesla 230 kV	C5	Diverge	Diverge	
CVLY-T-052		Eight Mile-Tesla 230 kV #1 and Stagg #4 230/60 kV	C3	Diverge	Diverge	
CVLY-T-053	Stagg-Tesla 230 kV	Eight Mile-Tesla 230 kV	B	<100%	107%	
		Weber-Tesla 230 kV and Eight Mile-Tesla 230 kV	C3	<100%	115%	
CVLY-T-054	Stagg-Eight Mile 230 kV	Stagg-Tesla 230 kV	B	<100%	107%	
		Lodi-Eight Mile 230 kV and Stagg # 4 230/60 kV	C3	<100%	111%	
CVLY-T-055	Tesla-Eight Mile 230 kV	Stagg-Tesla 230 kV	B	<100%	116%	
		Weber-Tesla 230 kV and Stagg #4 230/60 kV	C3	<100%	125%	
CVLY-T-056	Electra-Bellota 230 kV	Tiger Creek-Valley Springs 230 kV and Weber-Tesla 230 kV	C3	<100%	101%	Operating procedure
CVLY-T-057	Tesla-Weber 230 kV	N/A	A	<100%	108%	Reconductor
		Bellota-Tesla 230 kV	B	<100%	110%	
		Bellota-Tesla 230 kV and Collierville #1	B	<100%	118%	
		Bellota-Tesla 230 kV and Bellota-Warnerville 230 kV	C3	<100%	119%	
CVLY-T-058		Lockeford-Bellota 230 kV and Country Club-Hammer 60 kV	C3	N/A	Diverge	Mosher area reinforcement
CVLY-T-059		Country Club-Hammer-Mosher 60 kV and DCTL Lockeford-Bellota 230 kV and Brighton-Bellota 230 kV	D	Diverge	Diverge	
CVLY-T-060	Hammer-Country Club 60 kV	Stagg-Hammer 60 kV	B	117%	132%	
		Stagg-Hammer 60 kV and Stagg #4 230/60 kV	C3	122%	151%	
		Stagg-Hammer 60 kV	B	110%	125%	
		Stagg-Hammer 60 kV and Stagg #4 230/60 kV	C3	115%	143%	
		Stagg-Hammer 60 kV	B	110%	125%	
		Stagg-Hammer 60 kV and Stagg #4 230/60 kV	C3	115%	143%	
		Stagg-Country Club #1 60 kV and Stagg-Country Club #2 60 kV	C3	134%	151%	
		N/A	A	<100%	115%	
		Stagg-Tesla 230 kV	B	<100%	104%	
		Lodi-Eight Mile 230 kV and Stagg #4 230/60 kV	C3	<100%	110%	

ATTACHMENT II

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2010 California ISO Transmission Plan

Draft

3.3.4.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

Atlantic-Placer Voltage Conversion-Category A, B and C

Under normal conditions, the Placer 115/60 kV transformer could overload starting in year 2017. Also, under normal conditions, low voltages could appear in the area starting in year 2018. There are two potential overloads for category B single outage conditions starting in 2016. There are also multiple existing potential overloads, as well as low voltage and voltage deviations for category C conditions that can be mitigated by upgrading the Atlantic-Rocklin-Del Mar-Penryn-Placer system to 115 kV operation. This would be achieved by upgrading the existing Atlantic-Del Mar #1 and #2 60 kV to 115 kV operations, as well as rebuilding Placer-Del Mar to a 115 kV DCTL and having the entire system looped through. The most feasible implementation timeline for this upgrade is 2016 due to permitting and lead times. In the interim, load shedding will be used for most category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Madison-Vaca Dixon 115 kV Reconductoring-Category A

Under normal conditions, this line could overload by year 2014. Rerate is the preferred alternative. If rerate fails reconductoring this radial line could be a solution. The most feasible implementation timeline for this upgrade is 2014 due to permitting and lead times. This plan will be assessed further and included in the next annual ISO transmission plan.

In response to this proposal the ISO has received the Madison-Vaca Dixon 115 kV line rerate project from PG&E with operating date May 1, 2014. The ISO recommends that PG&E pursue this alternative as soon as possible. Equipment rerates do not need ISO approval.

Tesla-Weber 230 kV Reconductoring-Category A, B and C

Under normal conditions this line could overload by year 2016. There are also two potential overloads for category B single outage conditions and one for category C multiple contingency conditions starting in 2015. Reconductoring this network line could be a solution. The most feasible implementation timeline for this upgrade is 2015 due to permitting and lead times. This plan will be assessed further and included in the next annual ISO transmission plan.

Mosher Area Reinforcement-Category A, B, C and D

Under normal conditions the Hummer-Country Club and Stagg-Hummer 60 kV lines could overload starting in year 2015. Also for the loss of the Country Club-Hummer 60 kV, the Mosher substation transfers to the Lockeford #1 60 kV line potentially overloading it. The Mosher substation has over 50 MW of load and, as such, it should have a looped service. There are numerous category B and C contingencies with very high potential overloads as well as low voltages and voltage drops in both the Stagg 60 kV as well as Lockeford 60 kV when Mosher is served from either side. There are also some category C and D contingencies with divergence. Solution includes upgrading this substation to 115 kV or 230 kV service. Since the Mosher substation is in proximity of the Industrial substation a common project to upgrade both to preferably a new 230 kV service on a double circuit tower line coming from the general Eight Mile area would benefit both and possibly Hummer substation as well. Also it would constitute the third leg (out of four) into achieving a 230 kV ring around the Stockton area. The most feasible implementation timeline for this project is 2015 due to permitting and lead times. In the interim project implementation, due to permitting and lead times is 2011. In the interim load shedding will be used for this category C condition. This plan will be assessed further and included in the next annual ISO transmission plan.

3.3.4.5 Key Conclusions

Based on the ISO assessment Central Valley area had:

- 7 overloads and 14 low voltages under normal conditions;
- 29 overloads caused by 36 critical contingencies; 10 worst buses with low voltages caused by 12 critical contingencies, as well as 8 worst voltage deviations caused by 8 critical contingencies under single contingency conditions;
- 64 overloads caused by 71 critical contingency conditions, 28 worst buses with low voltages caused by 29 critical contingencies as well as 20 worst voltage deviations caused by 21 critical contingencies and 8 contingencies with divergent cases under multiple contingency conditions; and
- 12 divergent cases (potential voltage collapse) among the extreme contingency studied.

In order to address the identified overloads, the ISO proposed 42 transmission solutions while the request window produced 12 project proposals:

- 3 projects are being recommended for approval;
- 3 projects are recommended for denial;
- 6 projects are being evaluated by the ISO and they will move forward into the 2010 planning cycle for further analysis;

ISO will coordinate with PG&E regarding an additional 32 transmission solutions proposed by ISO.

Three projects, recommended for approval, will carry forward into the 2010 planning cycle and included in the planning assumptions. The remaining ISO proposals will be carried forward into the 2011 Transmission Plan.

Projects recommended for denial by ISO management:

Stockton 60 kV Energy Storage

Western Grid Development, LLC proposed a battery storage reliability-driven project, the Stockton 60 kV Energy Storage Project, to address the same reliability concerns as the Stockton "A"-Weber #1 60 kV reconductoring project. Western Grid Development, LLC proposed to build and own the battery storage projects, to turn the facilities over to the ISO's operational control and to recover the costs of the facilities through the ISO's TAC. However, ISO tariff section 24.1.2 provides that PTOS have the obligation to build, own and maintain reliability-driven projects.

The ISO staff considered the proposed battery storage project as an alternative to the reconductoring project to determine whether PG&E should be directed to install battery storage facilities. It was determined that although the Stockton Energy storage project addresses the same reliability needs as the preferred alternative, it does so at much higher cost. Therefore, the Stockton 60 kV Energy Storage Project is recommended for rejection.

Madison 115 kV Energy Storage

Western Grid Development, LLC proposed a battery storage reliability-driven project, the Madison 115 kV Energy Storage Project, to address the same reliability concerns addressed by the PG&E proposal to

rerate the Vaca-Madison 115 kV line. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control and to recover the costs of the facilities through the ISO's TAC. However, ISO tariff section 24.1.2 provides that PTOS have the obligation to build, own and maintain reliability-driven projects.

The ISO staff considered the proposed battery storage project as an alternative to the rerating of the Vaca-Madison 115 kV line to determine whether PG&E should be directed to install battery storage facilities. It was determined that there is no need for this project, or any other transmission upgrade or addition, because the Vaca-Madison 115 kV line can be rerated at minimal cost. Equipment rerates do not require ISO approval. The Madison Storage project addresses the same reliability needs as the preferred alternative but at much higher cost. Hence, the Madison 115 kV Energy Storage Project is recommended for rejection.

Sierra Peaker Project

The Cal-ISO recommends denial for this project.

This is a generation resource project that was proposed in order to solve reliability problems and achieve LCR deficiency reduction. However, it was not submitted as an alternative to transmission. Although this project directly competes with the new Rio Oso-Pleasant Grove 115 kV line, the ISO's transmsision access charge (TAC) provides for rate recovery of transmission assets, but not generation assets. Accordingly, this project is being recommended for rejection. The ISO suggests that this project be submitted in the generation interconnection process. The new Rio Oso-Pleasant Grove 115 kV line along with other alternatives to this plan will be assessed further and included in the next annual ISO transmission plan.

Auburn 60 kV Energy Storage

Western Grid Development, LLC proposed a battery storage reliability-driven project, the Auburn 60 kV Energy Storage Project, to address the same reliability concerns in the Placer area. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control and to recover the costs of the facilities through the ISO's TAC. However, ISO tariff section 24.1.2 provides that PTOS have the obligation to build, own and maintain reliability-driven projects.

The ISO staff considered the proposed battery storage project as an alternative to address any reliability concerns and to determine whether PG&E should be directed to install battery storage facilities. It was determined that the Placer area is very complex with both peak and off-peak transmission constraints. It requires a long-term solution. First, due to numerous binding constraints, it is not clear that this project can charge enough in order to help mitigate the binding constraints in the area. Second, this project only addresses a small part of the needs in the area, the Placer 115/60 kV transformer, and is not a long-term solution for the overall problems in the Placer area or the greater Atlantic-Placer area. ISO consideres all the possible reliability problems in the area as being interrelated and the solution or a number of solutions need to compliment each other and assure full compliance with standards. The Atlantic - Placer voltage upgrade along with other alternatives to this plan will be assessed further and included in the next annual ISO transmission plan. Therefore, the Auburn 60 kV Energy Storage Project is recommended for rejection.

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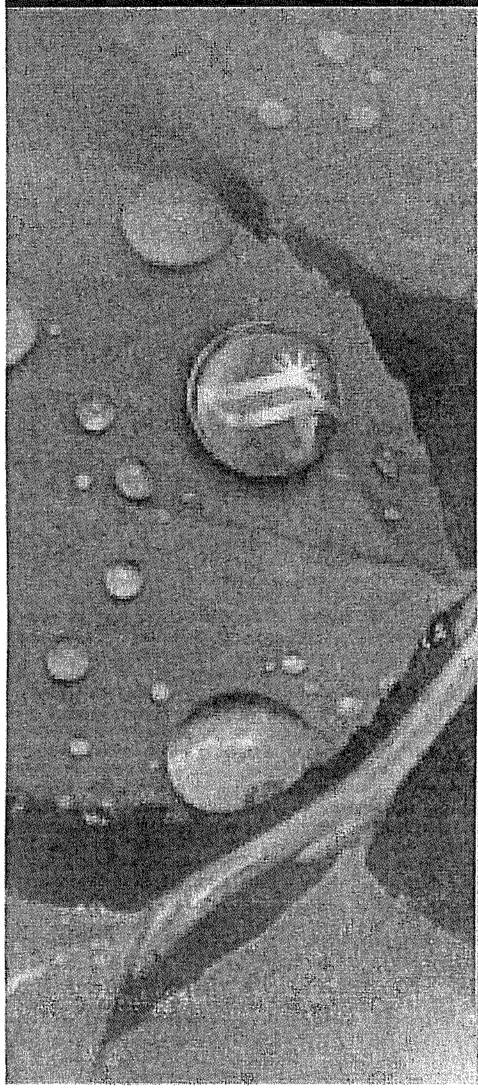
2010 ISO Transmission Plan Stakeholder Meeting #3



Catalin Micsa

Senior Regional Transmission Engineer North

Staff Recommendation on the 2010 ISO Transmission Plan Project Proposals

February 16, 2010

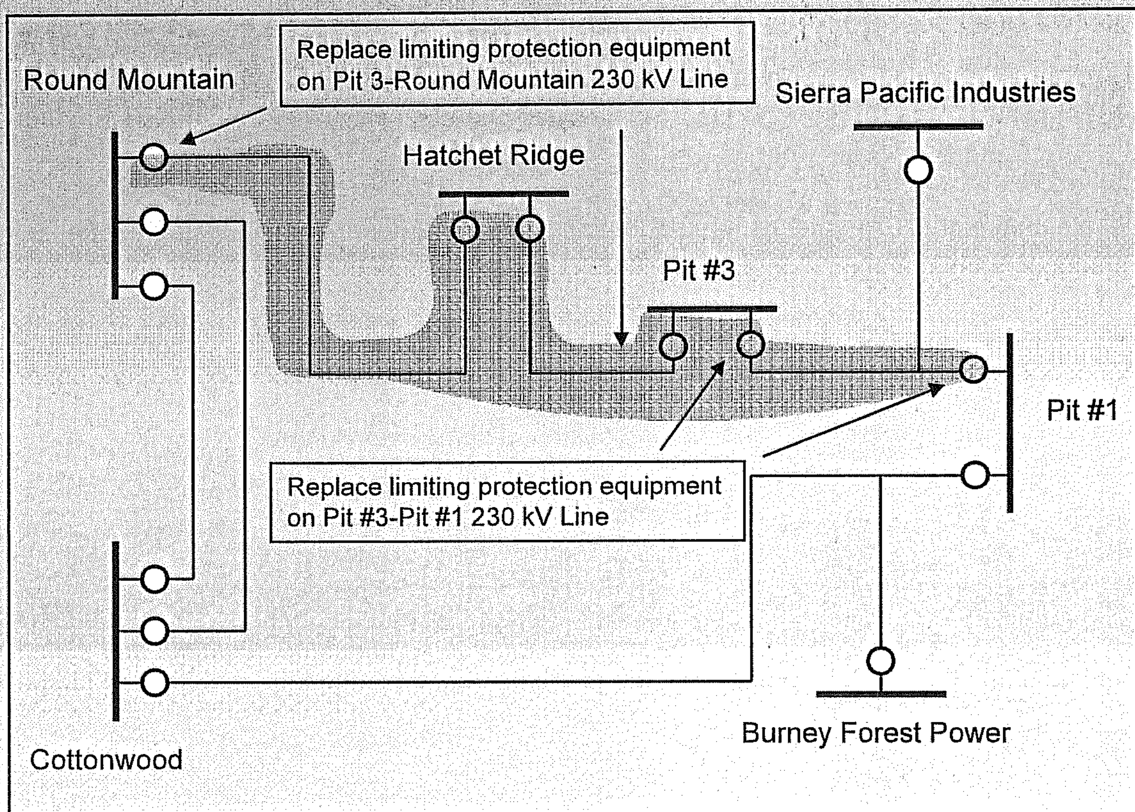
Overview of 2009 Request Window North Valley Area

ISO proposed a total of 10 reliability projects to address the potential problems related to potential reliability concerns in North Valley area. The ISO received 4 projects through the RW in response to ISO proposals.

- Recommended for Approval – 1 Project
- Denied – 0 Projects
- To be evaluated in the next transmission planning cycle – 3 Projects
- ISO will coordinate with PG&E on final project proposals – 6 Projects

Project Recommended for Approval (under $50M)

Pit 3-Pit 1 and Pit3-Round Mountain 230 kV Line Relays Replacement



Project Proponent: PG&E

Type of Project: Reliability

Needs: NERC Category B/C (2010) – tied to connection of Hatch Ridge wind farm

Project Scope

Upgrade terminal equipment

Costs: $1M

Other Considered Alternatives

None (limited scope)

Expected In-Service: December 1, 2010

Recommended Action: Approval by ISO Management

California ISO
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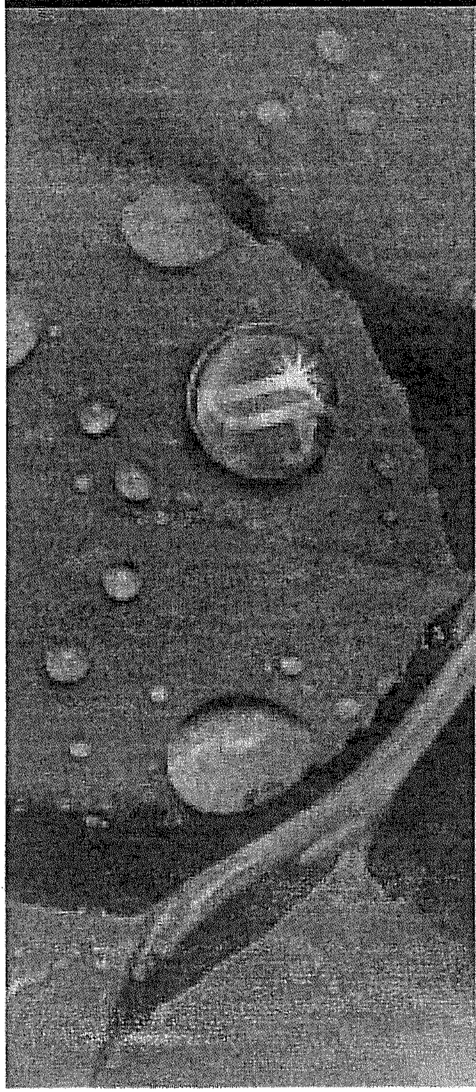
2010 ISO Transmission Plan Stakeholder Meeting #3



Catalin Micsa

Senior Regional Transmission Engineer North

Staff Recommendation on the 2010 ISO Transmission Plan Project Proposals

February 16, 2010

Overview of 2009 Request Window Central Valley Area

ISO proposed a total of 42 reliability projects to address the potential problems related to potential reliability concerns in the Central Valley area. The ISO received 12 projects through the request window in response to ISO proposals.

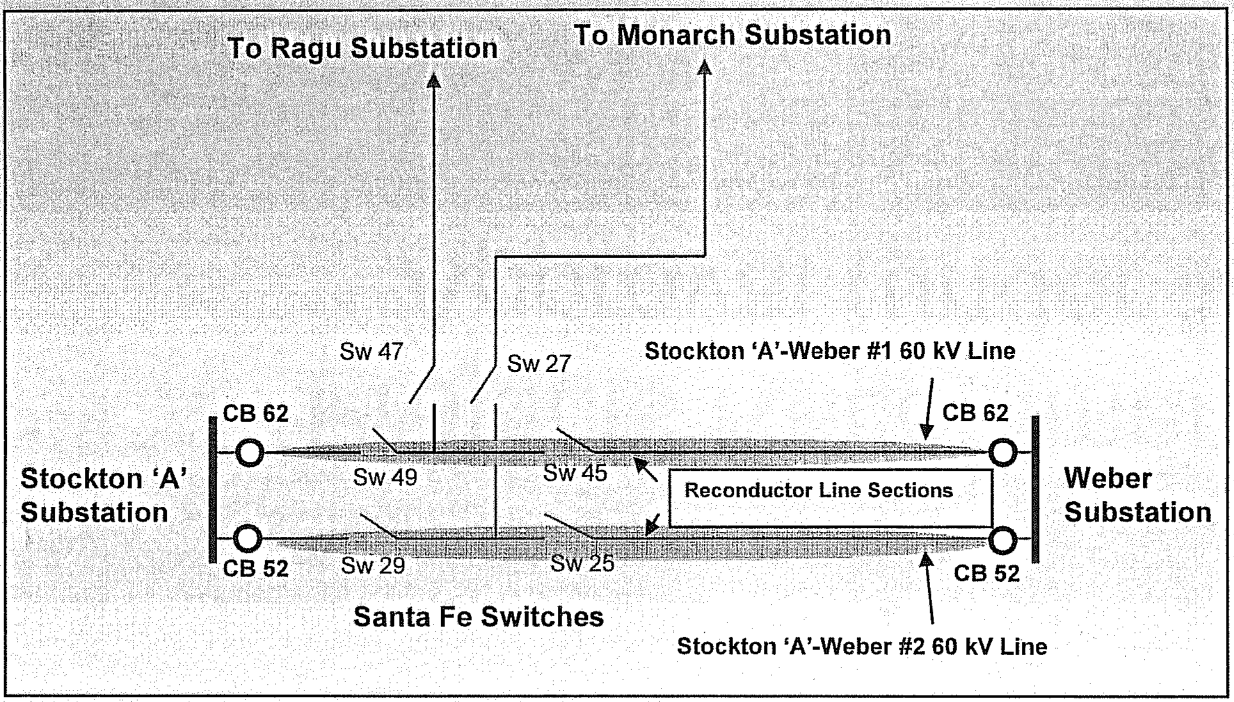
- Recommended for Approval – 3 Projects
- Denied – 4 Projects
- To be evaluated in the next transmission planning cycle – 5 Projects
- ISO will coordinate with PG&E on final project proposals – 32 Projects

ISO Recommendations on Proposed Projects in Central Valley Area

Project Name	Type of Project	Project Sponsor	Cost of Project	ISO Recommendation
Stockton "A"-Weber #1 & #2 60 kV Line Reconductor	Reliability	PG&E	$5-10M	Approve
Weber 230/60 kV Transformer #2&2A Replacement	Reliability	PG&E	$8-15M	Approve
West Sacramento Transmission Project	Reliability	PG&E	$1-2M	Approve
Stockton 60 kV Energy Storage	Reliability	WGD	$21M	Reject
Madison 115 kV Energy Storage	Reliability	WGD	$4.5M	Reject
Sierra Peakers Project	Reliability	Startrans	$100M	Reject
Auburn 60 kV Energy Storage	Reliability	WGD	$43.5M	Reject

Projects Recommended for Approval (under $50M)

Stockton "A"-Weber #1 and #2 60 kV Line Reconductor



Project Proponent: PG&E

Type of Project: Reliability

Needs: NERC Category A (2018), B/C (pre 2010)

Project Scope

Reconductor 9 miles between the two lines

Costs: $5-10M

Other Considered Alternatives

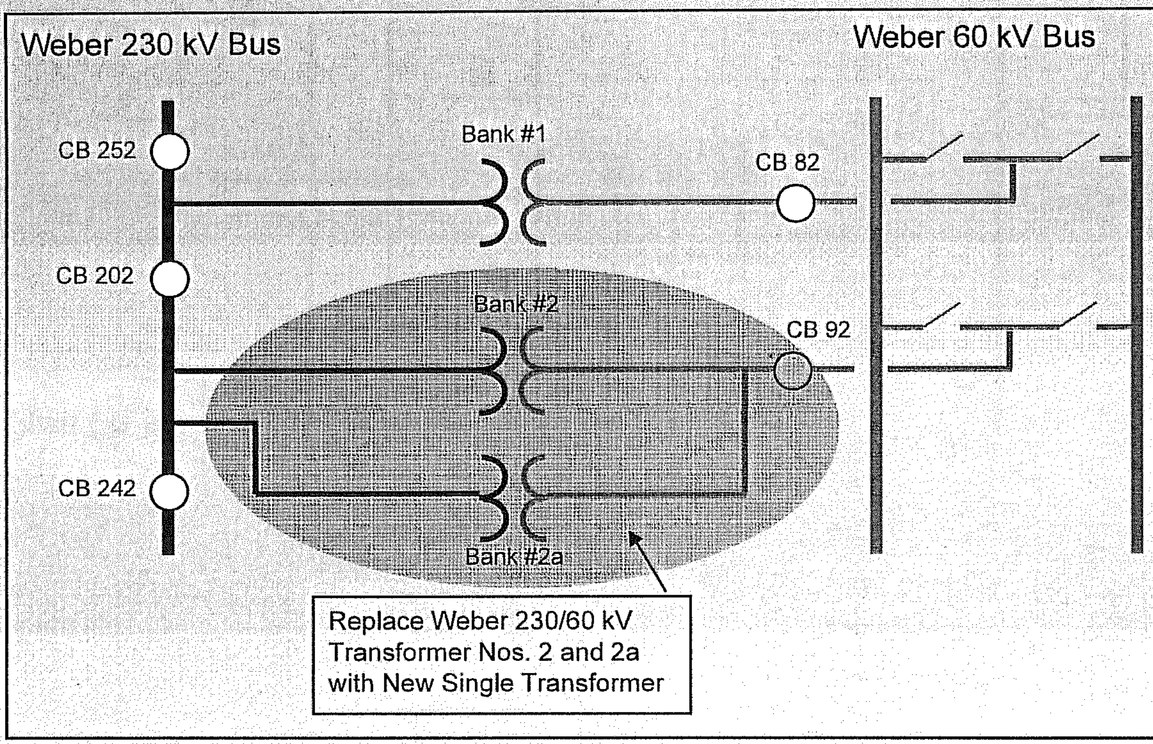
Rerate. (Does not cover the % overload expected)

Stockton 60 kV Energy Storage

Expected In-Service: May 1, 2011

Recommended Action: Approval by ISO Management

Weber 230/60 kV Transformer #2&2A Replacement



Project Proponent: PG&E

Type of Project: Reliability

Needs: NERC Category B/C (pre 2010)

Project Scope

Replace 230/60 kV transformer and bus tie

Costs: $8-15M

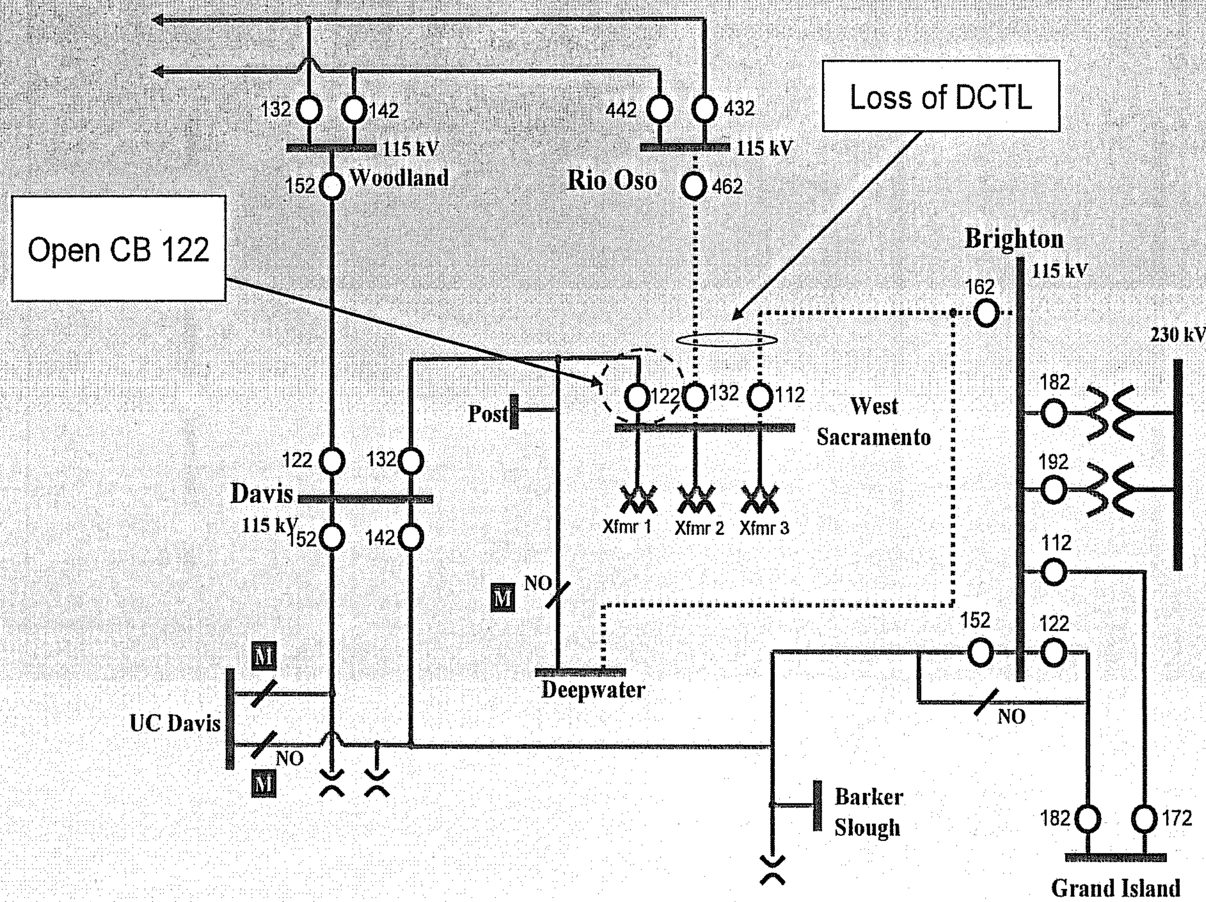
Other Considered Alternatives

None (limited scope)

Expected In-Service: May 1, 2013

Recommended Action: Approval by ISO Management

West Sacramento Transmission Project



Project Proponent: PG&E

Type of Project: Reliability

Needs: NERC Category C (pre2010)

Project Scope

Install SPS to trip load for DCTL

Costs: $1-2M

Other Considered Alternatives

None (limited scope) Vaca Dixon-Davis Voltage conversion is claimed as long-term solution (2014 and beyond)

Expected In-Service: December 1, 2010

Recommended Action: Approval by ISO Management

Projects Recommended to be Rejected

Stockton 60 kV Energy Storage

Project Proponent: Western Grid Development, LLC

Type of Project: Reliability

Needs: NERC Category A (2018), B/C (pre 2010)

Project Scope: Install 14 MW battery

Costs: $21M

Other Considered Alternatives: Stockton "A"-Weber #1 and #2 60 kV line reconductoring project plus the Stockton "A"-Weber #3 60 kV line rerate

Expected In-Service: March 30, 2014

Recommended Action: Reject this project.

California ISO
Your Link to Power

Final California ISO Transmission Plan

2010

April 7, 2010

Prepared by

Market & Infrastructure Development
California Independent System Operator Corporation

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3.3.4.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

Atlantic-Placer Voltage Conversion-Category A, B and C
Under normal conditions, the Placer 115/60 kV transformer could overload starting in year 2017. Also, under normal conditions, low voltages could appear in the area starting in year 2018. There are two potential overloads for category B single outage conditions starting in 2016. There are also multiple existing potential overloads, as well as low voltage and voltage deviations for category C conditions that can be mitigated by upgrading the Atlantic-Rocklin-Del Mar-Penryn-Placer system to 115 kV operation. This would be achieved by upgrading the existing Atlantic-Del Mar #1 and #2 60 kV to 115 kV operations, as well as rebuilding Placer-Del Mar to a 115 kV DCTL and having the entire system looped through. The most feasible implementation timeline for this upgrade is 2016 due to permitting and lead times. In the interim, load shedding will be used for most category C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Auburn 60 kV Energy Storage
Western Grid Development, LLC proposed a battery storage reliability-driven project, the Auburn 60 kV Energy Storage Project, to address some of the reliability concerns in the Placer area. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control. However, ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

Thus, the ISO will evaluate the battery storage project to determine whether PG&E should be directed to install such facility to address reliability needs in the area. The Placer area is very complex with both peak and off-peak transmission constraints driven by load, hydro and import patterns. Due to these factors, the operation of this system is extremely dynamic, with multiple constraints that need to be mitigated throughout the day. The ISO considers all the possible reliability problems in the area as being interrelated and any solution or solutions adopted to address these needs must complement each other and assure full compliance with reliability standards. In other words, this area requires a comprehensive long-term solution to address all the concerns. The ISO will consider the Atlantic - Placer voltage upgrade and the Auburn battery storage project, along with other possible options in the next ISO planning cycle to determine what facilities PG&E should be required to construct to meet the reliability needs in this area.

Madison-Vaca Dixon 115 kV Reconductoring-Category A
Under normal conditions, this line could overload by year 2014. Rerate is the preferred alternative. If rerate fails reconductoring this radial line could be a solution. The most feasible implementation timeline for this upgrade is 2014 due to permitting and lead times.

Madison-Vaca Dixon 115 kV Line Rerate
In response to this proposal the ISO has received the Madison-Vaca Dixon 115 kV line rerate project from PG&E with operating date May 1, 2014. The ISO recommends that PG&E pursue this alternative as soon as possible. Equipment rerates do not need ISO approval. The cost of the rerate is rather minimal usually less than $100,000 and the expected rating is about 12-15% higher. This line loading is increasing at a rate of about 1% per year; as such a successful rerate would mitigate then need for about 12-15 years, moving the need for a transmission project to 2026-2029 timeframe.

Madison 115 kV Energy Storage
Western Grid Development, LLC proposed a battery storage reliability-driven project, the Madison 115 kV Energy Storage Project, to address the same reliability concerns addressed by the PG&E proposal to

rerate the Vaca-Madison 115 kV line. WGD's proposed project has an initial capital cost of $4.5 million. Western Grid Development, LLC proposed to build and own the battery storage project, to turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO staff considered the proposed battery storage project as an alternative to the rerating of the Vaca-Madison 115 kV line to determine whether PG&E should be directed to install battery storage facilities. It was determined that there is no need for the battery storage project, or any other transmission upgrade or addition, because the Vaca-Madison 115 kV line can be rerated at minimal cost, significantly below the cost of installing a battery storage unit. It is expected that the rerate will increase the rating of the line by 12-15% and defer the need for any new transmission upgrade in this area. Once the line is rerated, there will not be any overload concerns. The Madison Storage project addresses the same reliability needs as the preferred alternative but at significantly higher cost. Hence, the Madison 115 kV Energy Storage Project is rejected.

Tesla-Weber 230 kV Reconductoring-Category A, B and C
Under normal conditions this line could overload by year 2016. There are also two potential overloads for category B single outage conditions and one for category C multiple contingency conditions starting in 2015. Reconductoring this network line could be a solution. The most feasible implementation timeline for this upgrade is 2015 due to permitting and lead times. This plan will be assessed further and included in the next annual ISO transmission plan.

Mosher Area Reinforcement-Category A, B, C and D
Under normal conditions the Hummer-Country Club and Stagg-Hummer 60 kV lines could overload starting in year 2015. Also for the loss of the Country Club-Hummer 60 kV, the Mosher substation transfers to the Lockeford #1 60 kV line potentially overloading it. The Mosher substation has over 50 MW of load and, as such, it should have a looped service. There are numerous category B and C contingencies with very high potential overloads as well as low voltages and voltage drops in both the Stagg 60 kV as well as Lockeford 60 kV when Mosher is served from either side. There are also some category C and D contingencies with divergence. Solution includes upgrading this substation to 115 kV or 230 kV service. Since the Mosher substation is in proximity of the Industrial substation a common project to upgrade both to preferably a new 230 kV service on a double circuit tower line coming from the general Eight Mile area would benefit both and possibly Hummer substation as well. Also it would constitute the third leg (out of four) into achieving a 230 kV ring around the Stockton area. The most feasible implementation timeline for this project is 2015 due to permitting and lead times. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Industrial Area Reinforcement-Category A, B and C
Under normal conditions the voltage at the Lockeford 230 kV bus can reach 0.94 pu by year 2019. There are a few single and numerous overlapping contingencies with low voltages, as well as voltage deviations in the area. There are also numerous Category C conditions with high potential overloads in this area. Designing an SPS that follows the ISO guidelines for this magnitude of different components is more challenging if at all possible and it does not constitute a long-term solution for the area. Further aggravating the situation is that the contingencies with higher voltage drop diverge if the Lodi CT is not on-line suggesting a potential voltage collapse in this area. The biggest substation in this area is Industrial with about 150 MW of load. Solution includes upgrading this substation to 115 kV or 230 kV service. Since the industrial substation is in proximity of the Mosher substation a common project to upgrade both to preferably a new 230 kV service on a double circuit tower line coming from the general Eight Mile area would benefit both and possibly Hummer substation as well. Also it would constitute the third leg (out of four) into achieving a 230 kV ring around the Stockton area. The most feasible implementation timeline for this project is 2015 due to permitting and lead times. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Tesla-Bellota 115 kV Area Reinforcement-Category A, B and C
Under normal conditions the Tesla-Kasson-Manteca 115 kV line could overload starting in year 2015. There are numerous single and overlapping contingencies with potential overloads in this area. This area has an existing LCR requirement as well. One of the solutions includes looping the Tesla-Stockton-Co-gen Junction 115 kV into the Vierra, Manteca, Kasson or Tracy substations and additional reconductoring if necessary. Another solution would be to upgrade part of the 60 kV Lee tap to 115 kV operations in order to close a 115 kV loop between the Ripon Co-gen and Ripon substation with additional reconductoring if necessary. Also another solution would be to move some of the substations with higher load like Tracy or Manteca to 230 kV service. The most feasible implementation timeline for this project is 2015 due to permitting and lead times. In the interim load shedding will be used for most category B and C conditions. This plan will be assessed further and included in the next annual ISO transmission plan.

Stockton "A"-Weber #1 60 kV Line Reconductoring-Category A, B and C
Under normal conditions the Stockton A-Weber #160 kV line could overload starting in year 2018. Also, currently there are two single and one overlapping contingencies with potential overload on the same line. Solution includes reconductoring 4.5 miles of the Stockton "A"-Weber #1 60 kV line from Weber to Santa Fee Switches. The most feasible implementation timeline for this upgrade due to permitting and lead time is 2011. In the interim load shedding will be used for both category B and C conditions.

Stockton "A"-Weber #2 60 kV Line Reconductoring-Category B and C
There is one single contingency starting in 2020 and one existing overlapping contingency with potential overload on this 60 kV line. Solution includes reconductoring 4.5 miles of the Stockton "A"-Weber #2 60 kV line from Weber to Santa Fee Switches. Most feasible project implementation, due to permitting and lead times is 2011. In the interim load shedding will be used for both category B and C conditions.

Stockton "A"-Weber #1 & #2 60 kV Line Reconductor
In response to the last two proposals the ISO has received the Stockton "A"-Weber #1 & #2 60 kV line reconductor project from PG&E with operating date May 1, 2011 at a cost of $5-10 Million. The ISO approves this project.
It has demonstrated that the preferred alternative is a prudent and technically sound solution to the identified reliability concerns. The reconductoring of portions of these two lines plus the rerate of the Stockton "A"-Weber #3 60 kV line is the most cost effective mitigation to the possible reliability concerns in the area.

Stockton 60 kV Energy Storage
Western Grid Development, LLC proposed a battery storage reliability-driven project, the Stockton 60 kV Energy Storage Project, to address the same reliability concerns as the Stockton "A"-Weber #1 and #2 60 kV reconductoring project. The battery storage unit would have an initial capital cost of $21 milllion, with the cost to increase as more MW are added. Western Grid Development, LLC proposed to build and own the battery storage projects, to turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the Participating Transmission Owner with a PTO Service Territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the Project Sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO staff considered the proposed battery storage project as an alternative to the reconductoring project to determine whether PG&E should be directed to install battery storage facilities. Although it was determined that the Stockton Energy storage project addresses the same reliability needs as the preferred alternative - reconductoring portions of the line, it does so at much higher cost. The reconductor project has a capital cost of $5-10 million. Therefore, the Stockton 60 kV Energy Storage Project is rejected.

Rio Oso/Gold Hill Area Voltage Support-Category A
Under normal conditions numerous 230 kV buses in the area could have below 0.95 pu voltage starting in year 2017. Solution includes installation of voltage support in the area. There is more than ample time for

ATTACHMENT JJ

Summary of identified thermal violations and proposed mitigation

Study Area: North Coast and North Bay Area - Summer peak conditions

Thermal Overloads

ID	Overloaded Facility	Worst Contingency(ies)	Category	Loading(%) 2014	Loading(%) 2019	ISO Proposed Solutions
NCNB-S-T-001	Lakeville 230/60 kV Bank #3	L-1 Fulton-Molino-Catati 60 kV #1 & T-1 Lakeville 230/60 kV #4	C (L-1/T-1)	105%	113%	Disable automatic switching during summer (equivalent to load dropping)
NCNB-S-T-002	Hopland 115/60 kV Bank #2	L-1 Ukiah-Hopland-Cloverdale 115 kV #1 & L-1 Geyser45-Eagle Rock 115 kV #1	C (L-1-1)	200%	192%	Develop operating procedure or load dropping scheme
NCNB-S-T-003	Vaca Dixon - Lakeville 230.00 kV Ckt #1	L-1 Geysers 9-Lakeville 230 kV #1 & L-1 Tulucay-Vaca-Dixon 230 kV #1	C (L-1-1)	112%	103%	
NCNB-S-T-004	Tulucay - Vaca Dixon 230.00 kV Ckt #1	L-1 Geysers 9-Lakeville 230 kV #1 & L-1 Lakeville-Vaca-Dixon 230 kV #1	C (L-1-1)	110%	102%	
NCNB-S-T-005	Bridgeville - Garberville 60 kV Line #1 (Between BRDGVLLE - FRUTLDJT)	L-1 Western Geo-Cloverdale 115 kV #1 & L-1 Mendocino-Cortina 115 kV #1	C (L-1-1)	114%	120%	
NCNB-S-T-006	Bridgeville - Garberville 60 kV Line #1 (Between GRBRVLLE - FTSWRDJT)			116%	120%	
NCNB-S-T-007	Mendocino - Redbud 115 kV #1 (Between REDBUD - REDBUDJ1)			106%	115%	
NCNB-S-T-008	Eagle Rock - Redbud 115 kV #1 (Between REDBUD - REDBUDJ2)			119%	129%	
NCNB-S-T-009	Eagle Rock - Redbud 115 kV #1 (Between REDBUDJ2 - CACHE J2)			109%	118%	
NCNB-S-T-010	Eagle Rock - Redbud 115 kV #1 (Between HGHLNDJ1 - CACHE J2)			102%	110%	
NCNB-S-T-011	Eagle Rock - Redbud 115 kV #1 (Between HGHLNDJ1 - LWRLAKEJ)			119%	129%	
NCNB-S-T-012	Geysers 3 - Cloverdale 115 kV Line #1 (Between CLOVRDLE - MPE TAP)	L-1 Mendocino-Cortina 115 kV #1 & L-1 Eagle Rock-Redbud 115 kV #1	C (L-1-1)	99%	107%	
NCNB-S-T-013	Fulton - Santa Rosa 115 kV Line #1 (Between FULTON - MONROE1)	L-1 Fulton-Santa Rosa 115 kV #2 & L-1 Corona-Lakeville 115 kV #1	C (L-1-1)	126%	134%	
NCNB-S-T-014	Fulton - Santa Rosa 115 kV Line #2 (Between FULTON - MONROE2)	L-1 Fulton-Santa Rosa 115 kV #1 & L-1 Corona-Lakeville 115 kV #1	C (L-1-1)	126%	134%	
NCNB-S-T-015	Santa Rosa - Coronoa 115 kV Line #1(the whole line but between BELLVUE - PENNGRVE has lowest rating)	T-1 Fulton 230/115 kV #4 & T-1 Fulton 230/115 kV #9	C (T-1-1)	197%	229%	
NCNB-S-T-016	Coronoa - Lakeville 115 kV Line #1			128%	148%	
NCNB-S-T-017	Sonoma - Pueblo 115 kV Line #1			127%	145%	
NCNB-S-T-018	Fulton - Calistoga 60 kV Line #1 (Between MIDDLTWN - CALISTGA)			116%	126%	
NCNB-S-T-019	Lakeville #2 60kV Line #1 (the whole line but between PETC_JCT - PETLMA A has the lowest rating)	L-1 Fulton-Molino-Catati 60 kV #1 & L-1 Petaluma C-Lakeville 60 kV #1	C (L-1-1)	136%	147%	
NCNB-S-T-020	Fulton - Pueblo 115 kV Line #1 (Between PUEBLO - STHELNJ1)	L-1 Lakeville-Sonoma 115 kV #1 & L-1 Lakeville-Sonoma 115 kV #2	C (L-1-1)	101%	107%	
NCNB-S-T-021	Mendocino - Clear Lake 60 kV Line #1 (Between MENDOCNO - UPPR LKE)	L-1 Homestk-Middletown-Eagle Rock 115 kV (new Line) L-1 & L-1 Clear Lake-Hopland Jct 60 kV #1	C (L-1-1)	<100%	101%	
NCNB-S-T-022	Mendocino - Willits - Fort Bragg 60 kV Line #1 (Between FRT BRGG - WILLITSJ)	L-1 Mendocino-Ukiah 115 kV #1 & L-1 Mendociso-Philo Jct-Hopland 60 kV #1	C (L-1-1)	<100%	104%	
NCNB-S-T-023	Clear Lake - Eagle Rock 60 kV Line #1 (Between CLER LKE - KONOCTI6)	L-1 Western Geo-Cloverdale 115 kV #1 & L-1 Eagle Rock-Redbud 115 kV #1	C (L-1-1)	145%	159%	
NCNB-S-T-024	Line between 32077 CORD PMP 60.00 kV To 32662 TULCY JT 60.00 kV Ckt #1	L-1 Cordelia Pump-Cordelia 60 kV #1 & L-1 Tulucay-Basalt 60 kV #1	C (L-1-1)	102%	103%	
NCNB-S-T-025	Ignacio - Mare Island 115 kV Line #2 (Between IGNACIO - HIGHLAND)	N/A	A	116%	126%	
		L-1 Ignacio-Mare Island 115kV #1	B (L-1)	142%	156%	
		L-1 Ignacio-Mare Island 115kV #1 & T-1 Ignacio 230/115kV #6	C (L-1/T-1)	146%	161%	Ignacio-Mare Island 230 Lines #1 and #2 kV reconductoring or Move load in the

ATTACHMENT KK

PG&E's
2009 Request Window Proposals

San Joaquin Valley and Los Padres Areas

Isaac Read

October 27, 2009

Folsom, CA

Transmission Project Overview

Projects Seeking CAISO Approval

- Corcoran 115/70 kV Transformer Replacement
- Reedley-Orosi 70 kV Line Reconductor
- Reedley-Dinuba 70 kV Line Reconductor
- Ashlan-Gregg and Ashlan-Herndon 230 kV Reconductor
- Morro Bay 230/115 kV Transformer Addition
- Los Padres Transmission Project
- Divide Transmission Project

Corcoran 115/70 kV Transformer Replacement

Background
- Corcoran Substation is located in Kings County and is part of Pacific Gas and Electric's Fresno Division. Corcoran Substation currently has three single phase 9.38 MVA 115/70 kV transformers.
- Corcoran 115/70 kV Transformer No. 2 is limited to 18.8 MVA by its 70 kV winding.

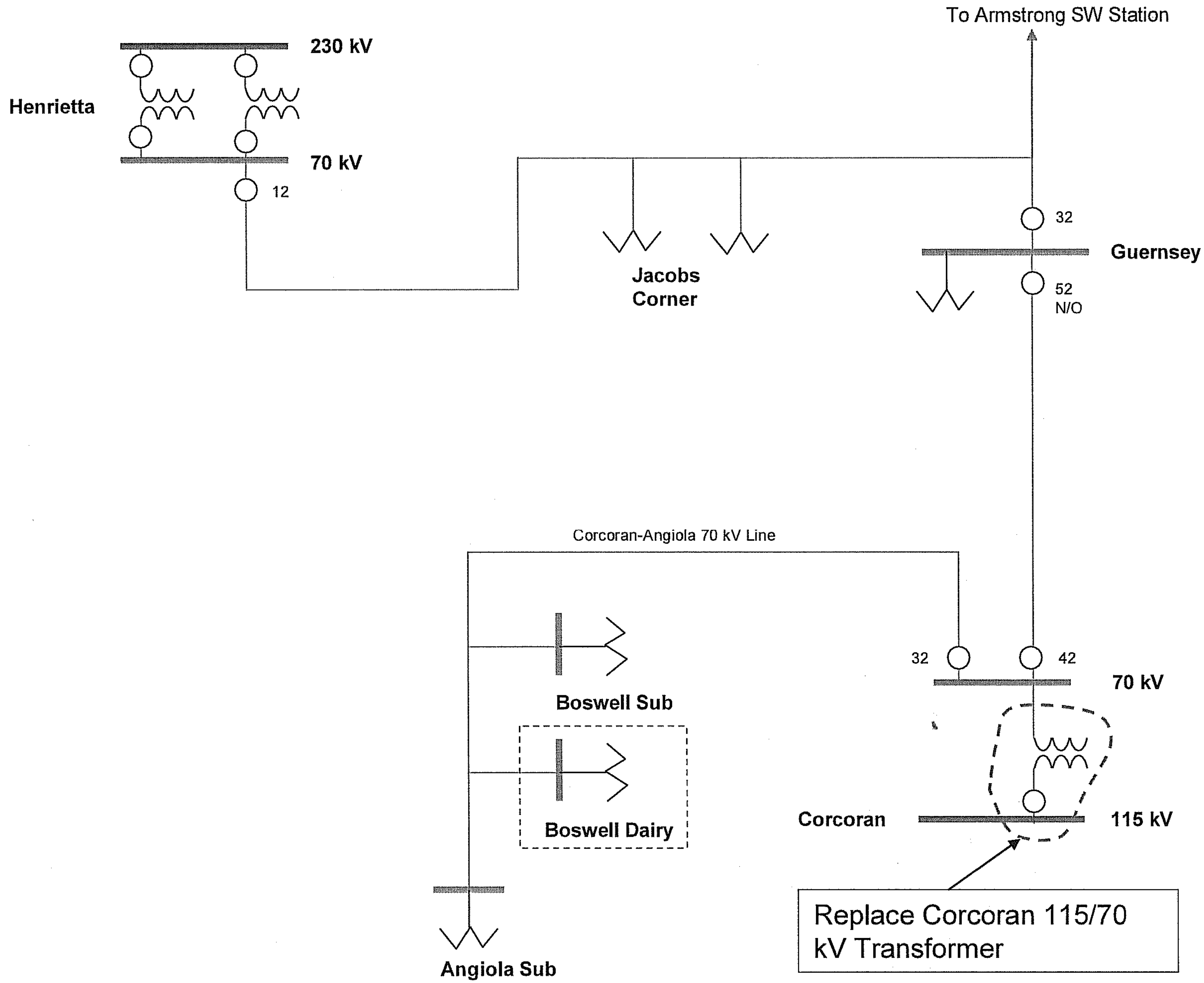
Assessment
- Normal Conditions (N-0)
  - Overloads Corcoran 115/70 kV Transformer No. 2

Scope
- Replace the current 115/70 kV transformer (rated to handle up to 90 MVA) at Corcoran Substation

Other Alternatives Considered
- Status Quo
- Convert the Corcoran-Angiola 70 kV Line to 115 kV Operation

In Service Date
- May 2012 or later depending on latest electric demand forecast

Cost
- $5M - $10M



To Armstrong SW Station
230 kV
Henrietta
70 kV
12
Jacobs
Corner
32
Guernsey
52
N/O
Corcoran-Angiola 70 kV Line
32
42
70 kV
Boswell Sub
Boswell Dairy
Corcoran
115 kV
Replace Corcoran 115/70 kV Transformer
Angiola Sub

2010 ISO Transmission Plan Stakeholder Meeting #3

California ISO
Your Link to Power

Robert Sparks

Lead Regional Transmission Engineer

Staff Recommendation on the 2010 ISO Transmission Plan Project Proposals

February 16, 2010

ISO Recommendations on Proposed Projects in Fresno and Kern Areas

Project Name	Type of Project	Project Sponsor	Cost of Project	ISO Recommendation
Corcoran 115/70 kV Transformer Replacement Project	Reliability	PG&E	$10- $20 M	Approve
Reedley-Orosi 70 kV Line Reconductor	Reliability	PG&E	$4 M	Approve
Ashlan-Gregg and Ashlan-Herndon 230 kV Line Reconductor	Reliability	PG&E	$ 8 M	Approve
Reedley-Dinuba 70 kV Line Reconductor	Reliability	PG&E	$15-$20 M	Approve
Guernsey 70 kV Energy Storage Project	Reliability	Western Grid Development	$15 M	Reject
Coppermine 70kV Energy Storage Project	Reliability	Western Grid Development	$15 M	Reject
Weedpatch 70kV Energy Storage Project	Reliability	Western Grid Development	$4.5 M	Reject

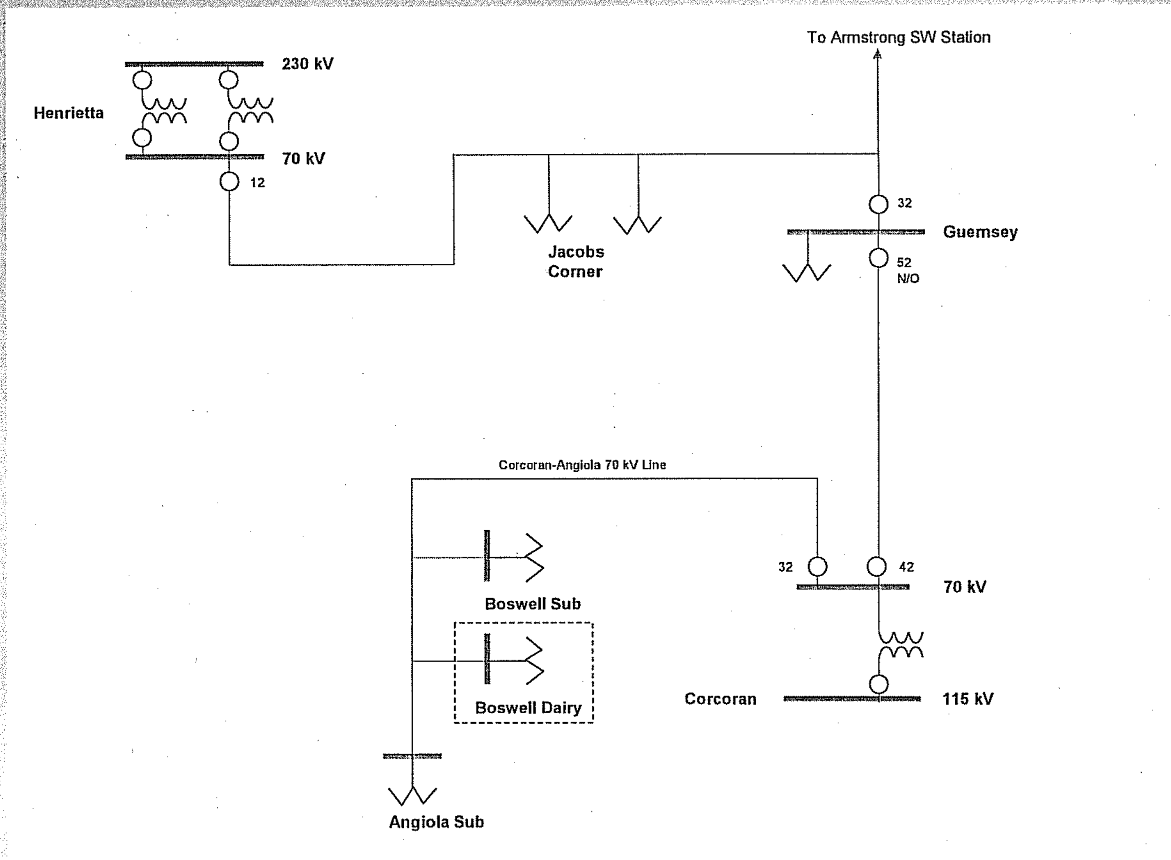
ISO Recommendations on Proposed Projects in Fresno and Kern Areas

Project Name	Type of Project	Project Sponsor	Cost of Project	ISO Recommendation
Reconductor Panoche-McMullin 230 kV line	Reliability	PG&E	Refer to Fresno Reliability Plan Projects slide	Approve
Reconductor Panoche-Helm 230 kV line	Reliability	PG&E	Refer to Fresno Reliability Plan Projects slide	Approve
Reconductor Helm-McCall 230 kV line	Reliability	PG&E	Refer to Fresno Reliability Plan Projects slide	Approve
Reconductor McMullin-Kearney 230 kV line	Reliability	PG&E	Refer to Fresno Reliability Plan Projects slide	Approve
Reconductor Mccall-Henrietta 230 kV line section	Reliability	PG&E	Refer to Fresno Reliability Plan Projects slide	Approve
Reconductor Certainteed-Legrand 115 kV line section	Reliability	PG&E	Refer to Fresno Reliability Plan Projects slide	Approve

Projects Recommended for Approval (under $50M)

California ISO
Your Link to Power

Corcoran 115/70 kV Transformer Replacement Project



Project Proponent: PG&E

Type of Project: Reliability

Needs: NERC Category A overloads (2010)

Project Scope

Replace the current 115/70 kV Transformer at Corcoran substation and installing a new 70 kV regulator both rated to handle up to 90 MVA.,

Costs: $10M to $20M

Other Considered Alternatives

Convert the Corcoran-Angiola 70 kV Line to 115 kV operation (higher cost)

See Guernsey battery project in later slide

Expected In-Service: 05 / 01 / 2012

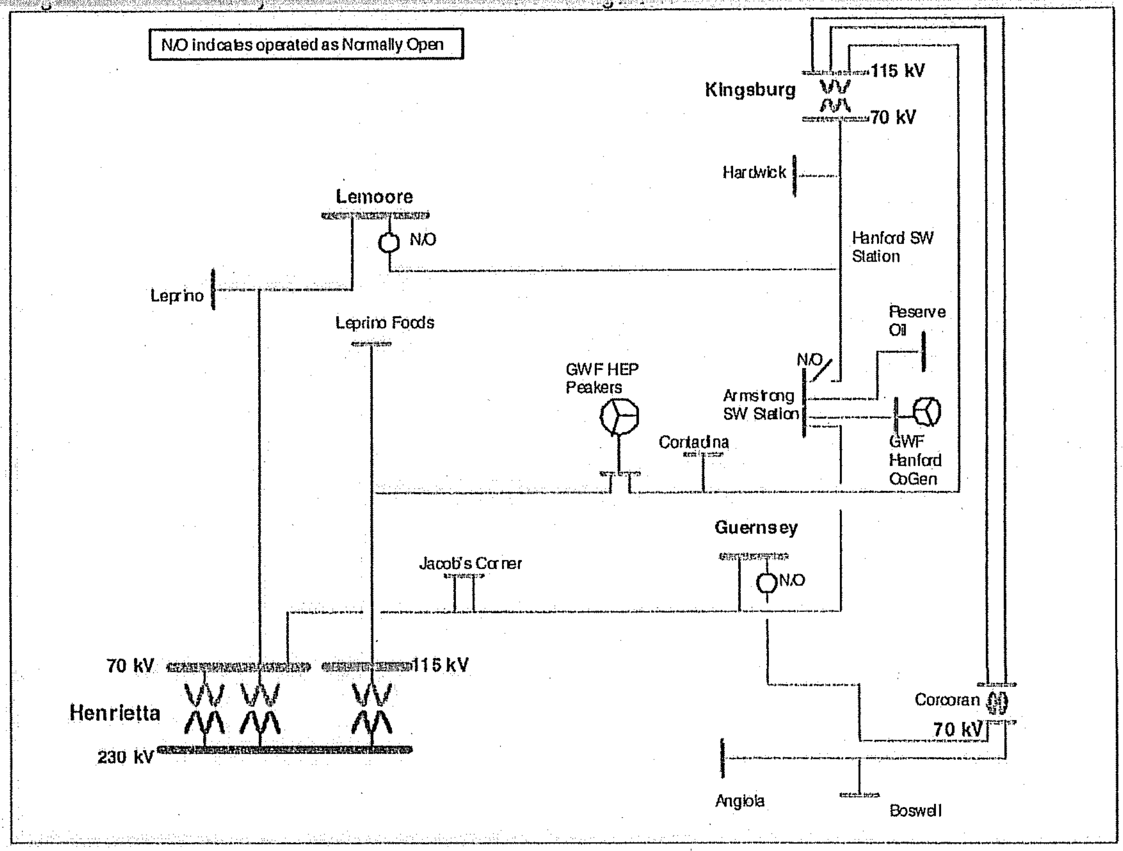
(transfer distribution load in 2010 and 2011)

Recommended Action: Approval by ISO Management

Projects Recommended to be Rejected

California ISO
Your Link to Power

Guernsey 70 kV Energy Storage Project



Project Proponent: Western Grid Development, LLC

Type of Project: Reliability

Needs: Restore radial load drop with backup source and mitigate Corcoran Bank overload

Project Scope

7 MW battery (growing to 14 MW over 30 yrs) with 7 hours storage at Guernsey sub

Costs: $15 M

Other Considered Alternatives

See PG&E's Corcoran bank replacement.

Expected In-Service: 12 / 30 / 2010

Reference: None

Discussion: This competes with PG&E's Corcoran project that came through the 2009 RW and is being recommended for approval

Recommended Action: Reject this project.

ATTACHMENT LL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Western Grid Development, LLC) Docket No. EL10-19-000

AFFIDAVIT OF ZIAD ALAYWAN
IN SUPPORT OF
WESTERN GRID DEVELOPMENT LLC
PETITION FOR DECLARATORY ORDER

I. QUALIFICATIONS AND PURPOSE

1. My name is Ziad Alaywan. I am currently employed by ZGlobal LLC as a consultant to Western Grid Development, LLC ("WGD") on energy, regulatory and technology issues.

2. I was employed by the Pacific Gas & Electric Company ("PG&E") between 1986-1996 and during that time I had a broad range of responsibilities. For example, from 1990-1996, I was responsible for managing PG&E's real time grid operations for Northern and Central California transmission systems. I was a member of the 7 x 24 operation staff and I served as a Transmission and Generation Dispatcher, as well as a Manager of Real Time Operations, of the PG&E Control Area.

3. In 1996, I led the start up efforts of the California Independent System Operator, Inc. ("CAISO"). My efforts focused on the development and implementation of the CAISO's bidding, scheduling, pricing, and settlements systems. As one of the first employees hired by the CAISO in May 1997, I was instrumental in the pioneering of that organization. I successfully led the implementation of the CAISO markets and operating systems within only one year.

Table 3 WGD proposed Project can transmit energy to any customers at any of the six stations

	2015	2020	2025	2030	2035	2040	2045
B1	22.8	24.3	25.9	27.7	29.5	31.5	33.6
B2	11.3	12.1	12.9	13.7	14.6	15.6	16.6
B3	13	13.9	14.8	15.8	16.8	18	19.2
B4	23.6	26.2	26.9	28.6	30.6	32.5	34.8
B5	13	13	13	13	13	13	13
Total	**83.7**	**86.4**	**93.4**	**98.8**	**104.6**	**110.6**	**117.2**
ESD Size		**5**	**9**	**13**	**18**	**23**	**29**

Table 4 - WGD Proposed ESDs

Year	Required ESD Size
2015	<5MW
2020	5MW
2025	9MW
2030	13MW
2035	18MW
2045	29MW

Other proposed sites are very similar to these sites in the CAISO transmission system.

VIII. THE WGD PROJECTS WILL NOT PARTICIPATE IN THE CAISO MARKETS OR SET PRICES

30. The WGD Projects will not participate in the CAISO Energy and Ancillary Service and Capacity markets in any shape or form. These WGD Projects are designed to provide transmission service only. Accordingly, the WGD Projects will not: (a) unduly discriminate against any other CAISO Market Participants who provide the Energy and Ancillary Services; (b) in any way skew the operation of the CAISO's markets for Energy and Ancillary Services, or skew the marginal cost of the Energy and Ancillary services; and/or (c) compromise the CAISO's independence by requiring the CAISO to exercise Operational Control over one supplier of products sold in the markets that it operates.

31. WGD is seeking for the WGD Projects to be treated like any other transmission assets that provide transmission services under a fixed rate of return without influencing the CAISO markets or other participants in the CAISO's markets. In particular, WGD, unlike other Market Participants, would never obtain revenues from the sale of energy and ancillary services.

32. The WGD Projects will not be market makers. The principles outlined earlier are fundamental to the proposed WGD Projects. As described previously, the WGD Projects will not influence or skew the operation of the CAISO Energy, Ancillary Service and Capacity markets at any time. The WGD Projects will not be operated by the CAISO or the local utility, so there is no question about the proper utilization of these ESDs as transmission assets.

IX. THE WGD PROJECTS ARE PART OF AN INTEGRATED TRANSMISSION NETWORK

33. The locations where WGD seeks to install these ESDs are part of an integrated network where a single line of ESD can serve as multiple feeds to multiple substations. As previously described, the sites where WGD will seek to implement the ESD solutions will provide transmission services for large geographic areas. The ESDs will operate as a part of the system that is strongly connected to the rest of the CAISO grid. The proposed utility alternatives for the sites that WGD is proposing are classified as transmission solutions and are subject to the transmission rate set by FERC.

X. THE WGD PROJECTS SHOULD BE EVALUATED BY THE CAISO UNDER ITS TRANSMISSION PLANNING PROCEDURES

34. The WGD Projects should be evaluated by the CAISO during the "open window" for transmission planning. The proposed WGD Projects are designed to provide transmission services to ratepayers using proven technology adapted by other utilities; solve the expected reliability violations; and provide a lower overall cost solution with less than a one year lead

ATTACHMENT MM

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Western Grid Development, LLC	))	Docket No. EL10-19-000

MOTION FOR LEAVE TO ANSWER AND
ANSWER OF WESTERN GRID DEVELOPMENT, LLC

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission" or "FERC"), 18 C.F.R. § 385.212 and 213 (2008), Western Grid Development, LLC ("WGD") hereby submits this Motion for Leave to Answer and Answer to the pleadings filed by parties in response to WGD's November 20, 2009 Petition for Declaratory Order of Western Grid Development, LLC ("Petition").

I. BACKGROUND

In the Petition, WGD requested that the Commission issue a Declaratory Order: (1) finding that the Energy Storage Devices ("ESD") that will be used in WGD's proposed projects, are properly classified as wholesale transmission facilities subject to FERC jurisdiction; (2) concluding that the WGD projects at locations where transmission reliability is at issue are entitled to incentive-based rate treatment pursuant to FERC regulations; (3) authorizing rate incentives for such WGD Projects; and (4) providing insight on whether the Commission perceives any barrier that could prevent the California Independent System Operator ("CAISO") from considering the WGD solution on equal footing with other utility and non-utility proposed transmission alternatives to solve reliability problems. Fourteen (14) parties submitted substantive interventions/comments/protests ("Pleadings") in response to the Petition.[1] WGD respectfully seeks to briefly respond to the Pleadings to assist the Commission in better understanding the issues that have been raised.

II. MOTION FOR LEAVE TO ANSWER

WGD seeks leave to submit this Answer to the Pleadings filed by parties in the captioned proceeding in order to clarify the issues and thereby aid in the Commission's decision-making process. WGD recognizes that Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (2008), does not provide for answers as a matter of right. However, the Commission permits answers where, as here, the information provided in an answer will facilitate the Commission's decisional process or aid in the explication of issues.[2]

WGD, therefore, respectfully requests that Rule 213(a)(2) be waived and that the Commission accept this Answer for good cause shown.

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1 The following parties filed Pleadings in this proceeding: California Independent System Operator, Inc. ("CAISO"); the Coalition to Advance Renewable Energy Through Bulk Energy Storage ("CAREBS"); the California Municipal Utilities Association ("CMUA"); the Electric Power Supply Association ("EPSA"); Ice Energy, Inc. ("Ice Energy"); the Modesto Irrigation District ("MID"); the M-S-R Public Power Agency and the City of Santa Clara, doing business as Silicon Valley Power ("M-S-R/SVP"); the National Electrical Manufacturers Association ("NEMA"); the Northern California Power Agency ("NCPA"); Public Service Electric and Gas Company, *et al.* ("PSEG Companies"); Southern California Edison Company ("SCE"); the Cities of Anaheim, Azusa, Banning, *et al.* ("Six Cities"); the California Department of Water Resources State Water Projects ("SWP"); and the Transmission Agency of Northern California ("TANC").

2 *New York Independent System Operator, Inc.*, 123 FERC ¶ 61,206, P 29 (2008); *California Independent System Operator Corp.*, 123 FERC ¶ 61,202, P 5 (2008); *Southwest Power Pool, Inc.*, 118 FERC ¶ 61,179, P 12 (2007) (accepting answers because they provided information that assisted the Commission in their decision-making process).

III. WGD ANSWER TO PLEADINGS

A. WGD Only Seeks for Approved WGD Projects Be Determined to Be Transmission Facilities; Not that All Batteries Be Defined as Transmission Facilities.

The Pleadings filed in this proceeding demonstrate that a wide variety of parties are interested in the appropriate use of energy storage devices to enhance the reliability of the wholesale transmission system. Due to the precedent that parties apparently believe could be established by the Petition being granted, many parties are urging the Commission to conduct a technical conference[3] or to establish a proposed rulemaking proceeding[4] before determining the very narrow issue that is presented: are the ESD at specific, discrete sites in California where the CAISO determines that they are the optimal transmission reliability solution (*i.e.*, "WGD Projects")[5] properly classified as wholesale transmission facilities subject to FERC jurisdiction?

WGD is not requesting that the Commission determine that every large battery device will necessarily perform a transmission function. WGD is also not requesting that the Commission determine that every large battery device should be entitled to incentive rate treatment.

Although some of the Parties express conditional support for the concept that the subject ESD could perform transmission functions,[6] several of the Pleadings suggest that WGD is seeking a much broader finding in the Petition.[7] WGD describes the very limited scope of the subject proceeding on page 4 of the Petition. WGD repeatedly emphasizes throughout the Petition that only ESD that participate in the CAISO Order No. 890 planning process and are

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3 PSEG Companies, p 5; NCPA pp 3-4.
4 PSEG Companies, pp 6-7; CAISO pp 24-25; CAREBS p 5; EPSA pp 4-5, 9-10.
5 Petition p 4.
6 *See* CAREBS p 5; Ice Energy at p 4; NEMA at p 2; PSEG Companies at pp 5-7.
7 *See, e.g.*, Ice Energy pp 4-6; SWP pp 7-9.

found by the CAISO to be the best solution to address transmission reliability problems that have been indentified by the CAISO, will qualify as the "WGD Projects" subject to the Petition. WGD is not seeking wholesale transmission classification for any of its proposed projects that are not selected through the open, non-discriminatory Order No. 890 planning process.

B. The Petition Is Not "Premature" Because a Commission Jurisdictional Determination Must Be Made Early in the CAISO Order No. 890 Planning Process To Facilitate Smart Grid Solutions.

Many of the Parties erroneously contend that the subject Petition is "premature" and seek a delay of a Commission determination,[8] apparently because they are confused as to the nature of the Petition. As described above, WGD's Petition is very narrow and focused because it is seeking assurance that its proposed transmission reliability projects will be evaluated by the CAISO on an equal footing with other transmission reliability solutions in the annual Order No. 890 regional planning process that commenced on November 30, 2009.

As discussed in the Petition,[9] Order No. 679 recognizes the value of a Commission determination of incentive rates for FERC-jurisdictional wholesale transmission facilities before a particular project has been approved through a regional transmission planning process. Such an early determination facilitates financing and investment in new facilities. Without such a determination, it will be much more difficult for advanced transmission technology projects, such as the WGD Projects, to be able to compete with traditional transmission solutions in an Order No. 890 transmission planning process.

Parties requesting a delay in a Commission determination, or contending that incentive rates should cannot be granted for "hypothetical" projects[10], do not understand the importance of

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8 TANC pp 7-9; SCE pp 4-7; M-S-R/SVP pp 13-15; MID pp 6-8; CMUA pp 4-6.
9 Petition, p 18.
10 M-S-R/SVP pp 11-13.

early Commission determinations regarding incentives. The extensive precedent justifying incentive rates that is found in the Petition[11] convincingly demonstrates that Commission precedent and the public interest supports incentive rate treatment at the earliest stage of an advanced transmission technology project.[12] If FERC defers or delays a decision on the Petition, WGD would be at a serious disadvantage in participating in the CAISO planning process, which could deny the CAISO ratepayers the benefits from the subject advanced transmission technologies.

Moreover, the suggestion by some Parties that the Commission should defer or delay a Commission decision regarding the Petition until after a comprehensive analysis of energy storage devices is completed, ignores the fact that WGD has already submitted the subject ESD projects into the CAISO's Order No. 890 transmission planning process. WGD has already committed the requisite resources to prepare and to participate in the CAISO transmission planning process (and WGD has already incurred significant costs in developing and filing the subject Petition) in order to provide the CAISO with lower cost, more efficient options to address existing reliability constraints. It would be fundamentally unfair to deny WGD a prompt resolution of the subject narrow issues while the Commission engages in more extensive analysis of energy storage issues related to energy and ancillary services markets, rather than transmission reliability.[13] In addition, if the Commission timely grants the subject Petition, a helpful real-

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[11] Petition pp 17-25.

[12] *See, e.g., ITC Great Plains*, 126 FERC ¶ 61,223 (2009) ("*ITC Great Plains*"); *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009); *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 (2008) ("*Tallgrass*"); *Green Power Express*, 127 FERC ¶ 61,031 (2009) ("*Green Power*").

[13] EPSA and other others have cautioned the Commission to not permit the Petition to establish binding precedent for all energy storage. EPSA pp 6-9. WGD has not requested a broad FERC decision on energy storage devices. Instead, WGD has specifically requested in the

world example of how energy storage devices can participate in transmission planning will be available for study.

C. The ESD Projects Will Result in <u>Lower</u> Net Costs for Addressing Required Reliability Upgrades Than Competing Transmission Projects.

Several of the Parties express concerns that the Commission should reject or delay a decision on whether the WGD Projects would be entitled to incentive rate treatment[14] apparently in the erroneous belief that such rate treatment will increase net costs for reliability transmission upgrades in California. The Pleadings ignore the reality that the WGD Projects will never be implemented and operated by the CAISO if they are not determined to be the least-cost, most effective transmission solutions to address identified reliability concerns in the CAISO. Thus, a timely and favorable FERC decision regarding the Petition will enable the ratepayers in CAISO to potentially gain the savings from a least-cost transmission reliability solution based upon ESD technologies. If the WGD Projects are selected by the CAISO, then ratepayers, for example, could avoid much more expensive alternative transmission solutions to address known reliability concerns. Even if the WGD Projects are not determined by the CAISO to be least-cost transmission solutions, a timely and favorable decision by the Commission would not result in increased transmission rates.

D. WGD Is Not Seeking to Provide Ancillary Services to CAISO.

Although some of the Parties allege that WGD is seeking to provide ancillary services to CAISO[15], the Petition clearly states[16] that the WGD Projects are designed to provide transmission services, not ancillary services (such as regulation service) to CAISO. CAISO, for example,

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Petition that the Commission only resolve the subject, narrow issues regarding the WGD Projects through a Declaratory Order. Petition, pp 9, 17 and 26.

14 TANC pp 9-11; Six Cities pp 5-8; M-S-R/SVP pp 11-12 and 16-19.

15 SWP pp. 3-5; Six Cities pp 3-5; CAISO pp 8-17.

16 Petition, pp 9-12.

contends that WGD has "not proposed any practical solution" to CAISO's concerns about operation of the ESD in providing energy or ancillary services.[17] This argument incorrectly assumes that the WGD Projects will be providing energy and ancillary services, even though the Petition makes it clear that the WGD Projects are designed to provide the same sort of transmission service, for example, as large capacitor transmission facilities that the CAISO is currently able to successfully operate.[18]

E. The WGD Projects Are Neither Demand Response Nor Pumped Storage Facilities.

Some of the Parties contend that the WGD Projects should not be classified as jurisdictional transmission assets because they are allegedly "energy efficiency"[19] or "pumped storage" facilities.[20] These erroneous contentions are addressed in the Petition, which distinguishes the operation of the subject energy storage devices from pumped storage facilities.[21] More importantly, WGD is seeking a narrow declaration that the WGD Projects would be classified as transmission facilities if they were selected by the CAISO to address transmission reliability concerns; WGD is not seeking a broad Commission determination that demand response programs or energy efficiency programs or pumped storage units should be classified as transmission facilities.

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17 CAISO pp. 20-24.
18 Petition, pp 10-12.
19 M-S-R/SVP p 13-16; SWP pp 3-5, 11-14.
20 CAISO pp 8-17; SWP p 10; 15-17.
21 Petition, 13-15. (Unlike pumped storage facilities, the WGD Projects will: (1) be operated as transmission facilities by the CAISO (just like existing large capacitor transmission facilities); (2) be providing voltage support rather than capacity to the CAISO system).

IV. NOTICE AND SERVICE

WGD has served a copy of this filing electronically, including attachments, upon all parties listed on the Commission's e-service list for this proceeding.

V. CONCLUSION

WHEREFORE, WGD respectfully moves for leave to file this Answer, and asks that the Commission consider this Answer in resolving the issues raised by commenters.

Respectfully submitted,

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