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September 23, 2015

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: San Diego Gas & Electric Company, Docket No. EL15-___-000
Petition for Declaratory Order

Dear Ms. Bose:

Pursuant to Rule 207 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 CFR § 385.207, Section 219 of the Federal Power Act, 16 U.S.C. § 824s, and Order No. 679, San Diego Gas & Electric Company ("SDG&E") respectfully submits for filing a Petition For Declaratory Order requesting authorization of an incentive treatment for the South Orange County Reliability Enhancement Project ("Project").

The Project consists of, among other things, adding a second independent 230 kilovolt ("kV") source to the southern Orange County at the proposed rebuilt Capistrano Substation. Currently, customers in this area are served by a 138 kV system sourced from a single 230kV to 138 kV substation. The California Independent System Operator ("CAISO") approved the Project to address identified reliability concerns in the area in its open and non-discriminatory transmission planning process, culminating in the CAISO's 2010-2011 Transmission Plan.

SDG&E requests authorization to recover one hundred percent of all prudently-incurred development and construction costs if the Project is abandoned or cancelled, in whole or in part, for reasons beyond SDG&E's control. Consistent with Commission policy, SDG&E has narrowly designed its requested incentive to address the risks and challenges associated with the development of the Project.

Concurrently with the electronic filing of this Petition, SDG&E is submitting by overnight mail a check in the amount of $24,730.00 for the filing fee as required by 18 CFR § 381.302(a).

Please contact me with any questions concerning the foregoing.

Respectfully submitted,

/s/ Georgetta J. Baker
Georgetta J. Baker
Attorney for
San Diego Gas & Electric Company

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	)	Docket No. EL15-___-000

PETITION FOR DECLARATORY ORDER OF
SAN DIEGO GAS & ELECTRIC COMPANY

Pursuant to Rule 207[1] of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), Section 219 of the Federal Power Act ("FPA")[2] and Order No. 679,[3] San Diego Gas & Electric Company ("SDG&E") respectfully files this Petition For Declaratory Order ("Petition") requesting authorization for incentive treatment for the South Orange County Reliability Enhancement Project ("Project" or "SOCRE").

The Project consists of, among other things, adding a second independent 230 kilovolt ("kV") source to the southern Orange County at the proposed rebuilt Capistrano Substation. Currently, customers in this area are served by a 138 kV system sourced from a single 230kV to 138 kV substation.

The California Independent System Operator ("CAISO") selected the Project in its open and non-discriminatory regional transmission planning process, culminating in the CAISO's 2010-2011 Transmission Plan, as the most effective, feasible solution to address the identified

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[1] 18 C.F.R. §385.207 (2015).

[2] 16 U.S.C. § 824s (2015).

[3] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) ("Order No. 679"), *order on reh'g*, Order No. 679-A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 ("Order No. 679-A"), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

reliability concerns in southern Orange County.[4] The proposed in-service date was 2015. The Project, however, has been pending approval by the California Public Utilities Commission ("CPUC") in the Certificate of Public Convenience and Necessity ("CPCN") permitting process since 2012.[5] The reliability circumstances for which the CAISO approved the Project are unchanged; southern Orange County customers are still served by a single source. Therefore, the perceived need for the Project remains unabated.

By this Petition, SDG&E requests authorization to recover one hundred percent of all prudently-incurred development and construction costs if the Project is abandoned or cancelled, in whole or in part, for reasons beyond SDG&E's control ("Abandonment Incentive"). The Abandonment Incentive is subject to SDG&E making the appropriate "just and reasonable" demonstration in a future FPA Section 205[6] filing to recover the prudently-incurred abandoned project costs in transmission rates.[7] SDG&E believes the Abandonment Incentive is warranted because:

- The Project meets the threshold requirement of Section 219 of the FPA of ensuring reliability in that it was identified and selected in the CAISO's open and non-discriminatory transmission planning process (CAISO 2010-2011 Transmission Plan), as necessary to address the identified reliability concerns; and

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4 Excerpts from the CAISO 2010-2011 Transmission Plan (May 18, 2011) are attached in Exhibit No. SDG-2. Page references to the Transmission Plan reflect the original document's pagination. Maps of the existing system and the Project are set forth at 208 and 210, respectively.

5 SDG&E will also be required to obtain additional permits from other Federal, State and Local entities to construct the Project. A list of the anticipated permits, authorizations and Requirements for the Project is attached as Exhibit No. SDG-3.

6 16 U.S.C. §824d (2012).

7 Order No. 679, FERC Stats. & Regs. ¶31,222 at P 165-66).

- The proposed Abandonment Incentive meets the nexus test because it is narrowly designed to address the regulatory and litigation risks and challenges, primarily permitting-related, associated with the development and construction of the Project.

I. BACKGROUND

A. Identification and Description of Petitioner

SDG&E is a California public utility corporation with its principal place of business at 8330 Century Park Court, San Diego, California. SDG&E is engaged in the transmission, distribution, and sale of energy services to approximately 3.5 million consumers in San Diego and Orange Counties, California, pursuant to regulation by the CPUC and this Commission. SDG&E is a Participating Transmission Owner, as that term is defined in the CAISO's FERC. SDG&E has transferred operational control of its transmission system to the CAISO.

Delivering clean, reliable power at reasonable rates through a safety-first culture is at the heart of SDG&E's service.

B. Description of the Project

Currently, SDG&E serves southern Orange County customers (approximately 129,000[8] customer accounts, or approximately 300,000 residents) by a 138 kV system sourced from a *single* 230 kV to a 138kV substation. As a result of that single source, southern Orange County customers are at risk of prolonged outages or other disruptions should problems occur at this substation. Such outages could impact public safety, such as health care, public schools, police and fire response, traffic signals, access to telecommunications, and the supply of fresh water

[8] The number of SDG&E's electric customers is sometimes shown as 120,000. The difference in numbers is based on timing and whether the number refers to individual customers or customer accounts. In both cases, the numbers are approximate.

and treatment of wastewater. The SOCRE Project, currently estimated to cost approximately $350-400 million, would mitigate these risks and improve resiliency by, among other things, providing a second independent 230 kV source to southern Orange County at the proposed rebuilt Capistrano Substation, which is at the load center for the area.

As noted in the Prepared Direct Testimony of David L. Geier ("Testimony") (Exhibit No. SDG-1), which is here incorporated by reference, the Project is designed to maintain the system's compliance with North American Electric Reliability Corporation ("NERC") requirements and to avoid the unnecessary loss of electric service to customers by ensuring that the system remains within applicable facility ratings following certain overlapping equipment outages and during necessary maintenance events. The Project also mitigates numerous other contingencies under which SDG&E would have to interrupt electric service to its customers, and mitigates the risk of southern Orange County being reliant on power from a single substation.

More particularly, SDG&E proposes to: (1) rebuild [and upgrade] the Capistrano substation in the City of San Juan Capistrano as a 230/138/12-kV substation ("San Juan Capistrano Substation"), and (2) construct a double-circuit 230-kV transmission line to connect the proposed San Juan Capistrano Substation to Talega Substation in San Diego County, east of the city of San Clemente. The addition of the proposed 230 kV double-circuit extension would bring a new 230 kV transmission source into South Orange County. The primary components of the Project, as proposed by SDG&E would include:

1. Rebuilding and upgrading the 138/12-kV 60-megavolt ampere (MVA)[9] air-insulated San Juan Capistrano Substation as a 230/138/12-kV 784-MVA gas-insulated substation that would be named San Juan Capistrano Substation;

[9] Substation capacity is typically expressed in terms of MVA for an alternating current electrical system.

2. Replacing a single-circuit 138-kV transmission line between the applicant's Talega and Capistrano substations with a new double-circuit 230-kV transmission line (approximately 7.8-miles long);
3. Relocating several transmission line segments (approximately 1.8 miles, total) adjacent to Talega and Capistrano substations to accommodate the proposed San Juan Capistrano Substation expansion and new 230-kV line; and
4. Relocating several *distribution line*[10] segments (approximately 6 miles) into underground *conduit*[11] and overhead on existing and new structures located between the Capistrano Substation and the Prima Deschecha Landfill.

The Project does not require SDG&E to acquire substantial new rights-of-way, although some new rights of way will be required.

In sum, not only does the Project address the reliability concerns that the CAISO identified in its 2010-2011 Transmission Plan, but it also benefits consumers in the immediate vicinity of the Project by using existing rights-of-way. This in turn avoids the need to take private property and minimizes both permanent and temporary construction-related environmental impacts. The underground segment benefits consumers in the vicinity by potentially eliminating any long-term visual and environmental impacts other than potential traffic disruptions during construction. Further, because the Project also involves replacing existing wood structures with new steel structures, the result is a reduction in potential fire risk and improved fire resistance. This benefits all SDG&E customers.

II. REQUEST FOR THE ABANDONMENT INCENTIVE

Congress enacted Section 219 of the FPA to promote, *inter alia*, capital investment in transmission facilities, including incentive transmission rates, and required the Commission to

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[10] Distribution lines are defined as electrical lines that operate at voltages below 50 kV.

[11] The term *conduit* refers to protective tubing through which electrical transmission and distribution cables would be installed. A polyvinyl chloride conduit is typically used for power line installations.

adopt implementing regulations.[12] Indeed, even prior to the enactment of Section 219, the Commission's authority to grant policy based incentives was well established.[13] Decisions regarding incentives "involve matters of rate design...[and] policy judgments [that go to] the core of [the Commission's] regulatory responsibilities."[14] In this light, Section 219 should be viewed as reflecting a Congressional judgment that traditional ratemaking policies may offer insufficient incentive for developers to invest in transmission system expansions and enhancements.[15] The statute therefore directed "the Commission to establish, by rule, incentive-based rate treatments to promote capital investment in transmission infrastructure."[16]

The Commission adopted its Section 219 implementing regulations in Order No. 679. In that Order, the Commission interpreted the statute as requiring, as a threshold matter, a demonstration that the project for which an applicant seeks incentives either promotes reliability or reduces the cost of delivered power by reducing transmission congestion.[17] There is a rebuttable presumption that this threshold Section 219 requirement is met if: "(i) the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (ii)

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12 *See generally* 16 U.S.C. §§ 824s ("Section 219"); Energy Policy Act of 2005, Pub. L. No.109-58, 119 Stat. 594 (2005).

13 Order No. 679-A at P 21 n.37.

14 *Id*. (citations and internal citation marks omitted).

15 *See* Order No. 679 at P 6.

16 *Pacific Gas and Electric Co*., 148 FERC ¶ 61,195 at P 7 (2014) (citing Pub. L. No. 109-58, § 1241, 119 Stat. 594 (2005)).

17 Order No. 679 at P 37; Order No. 679-A at P 5.

a project has received construction approval from an appropriate state commission or state siting authority."[18]

The Commission also stated that an applicant seeking rate incentives must demonstrate a nexus between the incentives requested and the proposed investment, including showing that the requested incentives address project-specific risks and challenges.[19] The "nexus test is met when an applicant demonstrates that incentives requested are 'tailored to address the demonstrable risks or challenges faced by the applicant.'"[20]

In its Policy Statement, the Commission provided additional guidance concerning requests for incentives under Section 219 and Order No. 679.[21] Specifically, the Policy Statement reaffirmed the Commission's policy of awarding risk-reducing incentives, including: Construction Work In Progress ("CWIP"); treatment of pre-commercial costs not included in CWIP as a regulatory asset, including deferred cost recovery; and recovery of prudently incurred costs if the project is abandoned or cancelled for reasons beyond the developer's control.

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[18] Order No. 679 at P 58. *See also Potomac-Appalachian Transmission Highline*, 122 FERC ¶ 61,188 at P 29 (2008). In Order No. 679-A (at P 49), the Commission clarified the operation of this rebuttable presumption by noting that a regional planning process must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.

[19] Order No. 679-A at P 27. *See also* 18 CFR § 35.35(d) (2014) ("The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project, and that resulting rates are just and reasonable.")

[20] *Ameren Services Co*., 135 FERC ¶ 61,142 at P 35 (2011) (quoting Order No. 679-A at P 40).

[21] *See* Policy Statement on Promoting Transmission Investment through Pricing Reform, 141 FERC ¶ 61,129 (2012) ("Policy Statement").

A. The Project Promotes Transmission System Reliability, as Determined Through a Fair and Open Regional Planning Process

Applicants seeking rate incentives are required to demonstrate that the project at issue either promotes reliability or reduces the cost of delivered power by reducing transmission congestion.[22] A rebuttable presumption that the FPA section 219 requirement is met applies in either of two circumstances: "(i) the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (ii) a project has received construction approval from an appropriate state commission or state siting authority."[23] As discussed more fully below, the CAISO selected the Project as necessary to address the identified reliability concerns in southern Orange County. The Project is pending construction approval from the CPUC, the appropriate state commission or state siting authority.

The 2010-2011 CAISO Transmission Plan explains the transmission planning process. Essentially, the Transmission Plan "provides a comprehensive evaluation of the [CAISO] transmission grid to identify upgrades needed to successfully meet California's policy goals, in addition to examining conventional grid reliability requirements and projects that can bring economic benefits to consumers."[24] Key analytics include, among other things, "[i]dentification of transmission upgrades and additions needed to reliably operate the network and comply with applicable [NERC and CAISO] planning standards and reliability requirements."[25] According to

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22 Order No. 679, P 37; Order No. 679-A at P 5.

23 *See* n.18, *supra*.

24 Exhibit No. SDG-2 at 8.

25 *Id*.

the Plan, compliance with those standards and reliability requirements "are a foundational element of the transmission plan."[26]

In evaluating the Project for reliability purposes, the CAISO performed detailed studies of the southern Orange County area to evaluate the overall reliability risks of southern Orange County. The studies revealed that the southern Orange County area is susceptible to multiple NERC Category C overloads by 2020, and that electric customers in the area are increasingly at risk of service interruption due to involuntary load shedding. The 2010-2011 Transmission Plan noted:

> Power flow study results of the peak load scenarios identified numerous facility loadings that exceeded their rated capabilities under Category C contingencies beyond 2015. All three alternatives considered here can mitigate the loading issues for Category C contingencies. In order to determine the most effective alternative, aspects beyond just the NERC compliance were taken into consideration. Historical data for bus outages at Talega and planned outages that put load at risk was accumulated and examined. It was quite evident that the lack of second source into southern Orange County puts more load at risk than the Category C issues noticed in the reliability assessment of the system. Hence, in order to improve the overall reliability of this system, it is important to bring another source into this area.[27]

The CAISO also evaluated three alternatives[28] and selected the Project, identified by the CAISO as Alternative 3, as "the most effective, feasible solution to meet the reliability needs of southern Orange County area."[29] Specifically, the CAISO identified two alternatives to the Project that would also meet NERC reliability standards. The CAISO rejected those alternatives,

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[26] *Id.* at 16. The Plan's reliability assessment is summarized at 16-18.

[27] Exhibit No. SDG-2, Transmission Plan at 210. The Transmission Plan is voluminous and no longer available on the CAISO website. Exhibit No. SDG-2 contains relevant excerpts from the Transmission Plan.

[28] *Id*. at 208-210.

[29] *Id*. at 210.

however, due to a combination of cost and effectiveness at improving system reliability. In concluding that the Project is preferable to the alternatives it considered, the CAISO stated:

> The project submitted by SDG&E (Alternative 1) aims to achieve [adding an additional bulk power connection to the South Orange County area], but Alternative 3 achieves similar reliability performance at a considerably lower cost. Alternative 2 mitigates the Category C issues through 2021, but fails to deliver another source into this area and hence fails to address the risk of load shedding due to contingencies at Talega. Alternative 3 [the Project] provides another source into southern Orange County system at very little extra cost compared to Alternative 2. It also offers a potential for future upgrades in case of further load growth. After a comprehensive analysis, the ISO staff concluded that SOCRUP Alternative 3 as the most effective, feasible solution to meet the reliability needs of southern Orange County area. Therefore, the ISO has found that the SOCRUP Alternative 3 project is needed to address the reliability concerns in the southern Orange County area. [30]

In sum, the 2010-2011 Transmission Plan concluded that: (1) "it is important to bring another source into this area"[31] to improve the overall reliability of the area and (2) the Project is "the most effective, feasible solution to meet the reliability needs of southern Orange County area."[32] Both of those determinations remain equally applicable today. Therefore, the need for the Project that the CAISO approved continues unabated.

The Commission has previously determined that projects found by a regional transmission planning process to ensure reliability are entitled to the rebuttable presumption established in Order No. 679. The Commission has also determined that because the CAISO's transmission planning process is a fair and open regional planning process, the FPA Section 219 threshold requirement is presumptively satisfied for a reliability project selected through that

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30 *Id*.

31 *Id*.

32 *Id*.

process.[33] Accordingly, the Project meets the rebuttable presumption to satisfy the reliability requirement.

A. The Requested Abandonment Incentive Satisfies the Nexus Test

Applicants for rate incentives are required to demonstrate a nexus between the incentives sought and the investment in question.[34] The nexus test requires that an applicant demonstrate that the requested incentives are rationally related and "tailored to address the demonstrable risks or challenges faced by the applicant."[35] It is no longer necessary for an applicant to make a "but for" showing – *i.e.*, that a project will not be built without the requested incentives – to satisfy the nexus requirement. Nor is it necessary for the applicant to demonstrate that the project for which it seeks incentives is a "non-routine" project.[36] Rather, applicants "must provide sufficient explanation and support" regarding how the incentives requested are tailored to address the risks and challenges of the project.

As discussed below, the requested Abandonment Incentive is narrowly tailored to address the risks and challenges of the Project, *i.e.,* primarily, permitting-related regulatory and litigation risks associated with the CPCN permitting process. Accordingly, the requisite nexus test is satisfied.

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33 *San Diego Gas & Electric Co.,* 151 FERC ¶ 61,011 at P 30, *Citizens Energy Corp*., 129 FERC ¶ 61,242 at P 16 (2009) (holding that approval through the CAISO's transmission planning process was a factor establishing rebuttable presumption). *See also Pacific Gas and Electric Co*., 148 FERC ¶ 61,195 at P 14 (2014).

34 Order No. 679 at PP 1-2, 26. *See also* 18 CFR § 35.35(d) (2015).

35 Order No. 679-A at P 115; Order No. 679 at P 48.

36 *See* Policy Statement at P 10 (The Commission "re-frame[d] its application of the nexus test" such that it "no longer rel[ies] on the routine/non-routine analysis." *Id*.). Nonetheless, Mr. Geier notes in his testimony that most of SDG&E's transmission projects do not require CPCN authorization. "Those that do require a CPCN tend to be the largest, most costly, most complex and most contentious projects that SDG&E is developing at any given time." Exhibit No. SDG-1 at 12.

1. The Permitting Process Presents Substantial Challenges

SDG&E must obtain various Federal, state and local permits or authorizations.[37] Among other things, SDG&E will require review from the military to construct the portion of the Project located on Camp Pendleton grounds, implicating the National Environmental Policy Act. As discussed more fully below, *infra* at 13, the CPUC's CPCN permitting process is lengthy and complex and appears to contain the greatest level of risk and uncertainty for Project commencement and completion.

Exhibit No. SDG-3 provides a *Step-by-Step Guide* to the CPUC's CPCN process. The formal start of the process is the filing of a CPCN application, which includes the Proponent's Environmental Assessment ("PEA"). The PEA identifies the alternatives the applicant considered and explains why the applicant chose the selected alternative. Thereafter, the CPUC staff reviews the application for completeness and once it is deemed complete, the CPUC commences its two-prong review of CPCN application: an environmental review and a purpose and need review. Specifically, the CPUC, as lead agency under the California Environmental Quality Act ("CEQA"), conducts an environmental review. Under this review track, the CPUC will conduct an independent evaluation of any environmental issues that must be addressed in the preferred route, including considering alternatives to the proposed project. The CPUC will also solicit comments from other agencies and from the public. Ultimately, the CPUC could approve or modify the Project, including imposing mitigation measures for any significant environmental impacts, or could reject the Project.

In addition to its environmental review of the Project, the CPUC also conducts a purpose and need review. Pursuant to California law, the purpose and need review includes consideration

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[37] *See* Exhibit No. SDG-5.

of project alternatives. Such alternatives are not only other transmission solutions but are much broader, including "demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation…and other demand reduction resources."[38] As with the environmental review, possible outcomes of the purpose and need review include approval, with or without modifications, or rejection. Both review tracks typically involve broad public participation, including administrative litigation before an administrative law judge.

While SDG&E has no assurance that it will receive all of the required permits, as a general matter, SDG&E anticipates that the CPCN will be the most challenging permit to obtain. The CPCN process routinely is lengthy, complex, resource-intensive, and often contentious.[39] And it has been especially so for the SOCRE Project. Indeed, SDG&E has been so concerned about the three-year delay in the CPUC's processing of the CPCN application that SDG&E recently submitted a letter to the President of the CPUC, co-signed by Mr. Geier, noting the three-year delay and delineating concerns about anomalies in the environmental review and application process. *See* Exhibit No. SDG-4.

For instance, SDG&E filed the CPCN application on May 18, 2012. It was deemed complete in January 2013 and the CEQA scoping meetings and comment period were complete by February 2013. However, a Draft Environmental Impact Report ("DEIR") was not circulated until two years later, in February 2015. Six months later, in August 2015, the DEIR was revised and recirculated with new proposals. It appears that hearings will be scheduled for November 2015. SDG&E has requested issuance of a final decision on the Project in the first quarter 2016

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[38] California Public Utilities Code §1002.3.

[39] For instance, SDG&E filed its CPCN application for the Sunrise Powerlink Project on August 4, 2006. It was contested for various reasons and the CPUC did not issued its decision until December 18, 2008.

to provide SDG&E with a realistic opportunity to energize the Project that the CAISO approved in its 2010-2011 Transmission Plan to address comprehensively the reliability needs in southern Orange County.

Of course, as noted below, it is not clear whether and to what extent the final decision will permit the Project, as approved by the CAISO, to go forward or impose environmental mitigation measures or other conditions on the Project which may render its construction completely unachievable, or unachievable within the time-frame needed to address comprehensively the reliability issues that the CAISO in its 2010-2011 Transmission Plan.

In sum, the regulatory risks associated with obtaining regulatory approvals to construct the Project in a timely manner are substantial and challenging.

2. The Abandonment Incentive Appropriately Mitigates SDG&E's Development Risk

The Commission permits recovery of 100% of the prudently incurred costs for a project that is cancelled for reasons beyond an applicant's control. The Commission's reasoning is that permitting cost recovery serves "an effective means to encourage transmission development by reducing the risk of non-recovery of costs."[40] This incentive thus alleviates developers' disincentive to invest if their lenders and shareholders otherwise would be required to bear the costs of projects that must be abandoned for reasons the developer cannot control.

The Commission has determined that abandoned plant recovery is appropriate in circumstances such as where a project developer has been unable to obtain necessary regulatory

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[40] Order No. 679 at P 163. *See also* Policy Statement at P 14 (citing Order No. 679 at P 163) ("[T]he incentive that allows for 100 percent recovery of prudently incurred costs of transmission facilities that are abandoned for reasons beyond the control of the transmission owner…reduces the regulatory risk of non-recovery of prudently incurred costs.").

approvals or rights of way.[41] As explained in Mr. Geier's Testimony, and as discussed above, SDG&E faces risks such as environmental, regulatory, siting, and permitting risks that are outside of SDG&E's control and could lead to abandonment of the Project.[42] These are precisely the kinds of risks in SDG&E's development of the Project that the Commission has previously found to warrant abandoned cost recovery.[43]

Moreover, affording SDG&E abandoned cost recovery encourages not only timely but also smarter development of transmission infrastructure. Absent the opportunity to recover prudently incurred costs, utilities such as SDG&E would be forced to minimize exposure by undertaking less development work in the pre-approval stage of the Project. SDG&E has already begun detailed engineering work to expedite procurement and construction after receipt of regulatory approvals. Abandoned cost recovery will allow SDG&E to continue to move forward with the significant pre-approval development work required to construct the Project in a timely manner should SDG&E obtain the necessary approvals and, more generally, would send a positive signal to other developers in the marketplace.

3. The Abandonment Incentive Is Narrowly Tailored To Address the Risks and Challenges of the Project

The Commission has stated that in making its determination concerning whether an applicant has met the nexus test, "the Commission will examine the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project."[44] Order No. 679 permits utility sponsors

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[41] *See* Order No. 679 at P 163. *See also S. Cal. Edison Co.*, 129 FERC ¶ 61,246 at PP 67-68 (2009).

[42] Exhibit No. SDG-1 at 15-18.

[43] *See*, *e.g.*, *Pacific Gas and Electric Co.,* 148 FERC ¶61,195 at P 15 (2014).

[44] Order No. 679-A at P 21.

of abandoned transmission projects to recover 100% of their prudently incurred development costs "if such abandonment is outside the control of management," on the ground that this incentive will "encourage transmission development by reducing the risk of non-recovery of costs."[45]

As a general matter, assurance that prudently incurred costs can be recovered should abandonment be required for a reason beyond the developer's control, supports investment of significant equity capital on project development. Development activities include permitting and environmental studies, detailed engineering and design, contracting labor and materials, and, on certain projects, acquiring right-of-way. Without abandoned plant cost recovery protection, developers are at risk for the costs of these development activities. However, the ultimate decision on whether a transmission project that requires regulatory approvals can proceed rests with permitting agencies and regulatory bodies that are not necessarily under an obligation to approve or act timely on a proposed project or with commercially acceptable conditions.

SDG&E has already expended substantial resources, both direct spending and internal labor, in order to develop a Project that had the greatest likelihood of satisfying the reliability requirements of SDG&E's customers in southern Orange County, without assurance of cost recovery for these development costs, because of its obligation to ensure ongoing safe and reliable service. Mr. Geier estimates that thus far, SDG&E has incurred in excess of $31 million toward the development of the Project, a figure that SDG&E anticipates will approach $35 million by the end of calendar year 2015. A substantial percentage of those costs were incurred

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45 Order No. 679 at P 163; *RITELine Illinois, LLC*, 137 FERC ¶ 61,039 at PP 84-85 (2011); *Pioneer*, 126 FERC ¶ 61,281 at P 75 (2009).

on the preparation of the utility's development plan, and were incurred with no certainty that SDG&E's development plan would be approved by the CPUC.

SDG&E believes that the Project should receive all necessary regulatory approvals. SDG&E does not expect to need to abandon the Project; yet the possibility remains that such abandonment may be necessary for reasons beyond SDG&E's control. For instance, an inability to obtain the requisite approvals or to implement any required environmental mitigation could result in Project cancellation. Further, subsequent regulatory or judicial actions could result in SDG&E needing to abandon the Project even if SDG&E receives all necessary approvals. If the timing of obtaining approvals or implementing required environmental mitigation measures does not allow SDG&E to satisfy the CAISO's desire to have the Project in service in a reasonable time-frame that could also jeopardize the viability of the Project.

As the Commission observed, "the incentive that allows for 100 percent recovery of prudently incurred costs of transmission facilities that are abandoned for reasons beyond the control of the transmission owner…reduces the regulatory risk of non-recovery of prudently incurred costs."[46] The requested Abandonment Incentive, therefore, is important from a financial perspective and tailored to the risks and challenges that SDG&E will face in developing this Project.[47] This is especially important where, as here, the Project enhances reliability for southern Orange County in an environmentally sound manner.

For the foregoing reasons, SDG&E requests that the Commission find that SDG&E has appropriately met the nexus requirement and is authorized to recover 100 percent of its prudently

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46 Policy Statement at P 14.

47 SDG&E utilizes a formula to establish its transmission rates, which provides a mechanism for recovery of eligible costs. In this filing SDG&E is not proposing rate changes pursuant to FPA Section 205; however, SDG&E will reflect the effect of the requested incentives in future formula rate update filings at appropriate times.

incurred costs of developing the Project should SDG&E be required to abandon or cancel the Project for reasons beyond SDG&E's control. SDG&E understands such authorization is subject to SDG&E making a future FPA Section 205 filing to recover such costs should SDG&E be required to abandon or cancel the Project, in whole or in part.[48]

III. TECHNOLOGY STATEMENT

Order No. 679 requires applicants for incentive rates to submit a technology statement discussing whether advanced technologies will be employed in developing a project. Section 1223 of the Energy Policy Act of 2005 defines the term "advanced transmission technologies" as "technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility."[49] SDG&E will use several "advanced transmission technologies" in developing the Project, including: LIDAR, helicopters, optical ground wire and fiber optic cable, and mobile device applications. SDG&E will also use substation-related advanced technologies, including: gas-insulated substation technology, condition-based monitoring and supervisory control and data acquisition infrastructure. SDG&E's use of these advanced technologies is explained in Mr. Geier's Testimony and incorporated here by reference here.[50]

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48 Order No. 679 at PP 163-166.

49 42 U.S.C. §16422(a) (2014).

50 Exhibit No. SDG-1 at 25-27.

IV. COMMUNICATIONS

All communications, correspondence, and documents related to this proceeding should be served upon the following persons:

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A copy of this Petition has been served on the California Public Utilities Commission and on the CAISO. Attachment A to this filing includes a notice of filing suitable for publication in the *Federal Register*.

V. MATERIALS SUBMITTED HEREWITH

Together with the Petition for Declaratory Order, SDG&E hereby submits each of the following:

1.	Attachment A:	Notice of Filing suitable for publication in the *Federal Register*
2.	Exhibit No. SDG-1	Prepared Direct Testimony of David L. Geier
3.	Exhibit No. SDG-2	Relevant Excerpts from CAISO 2010-2011 Transmission Plan Approving the SOCRE Project (May 18, 2011)
4.	Exhibit No. SDG-3	Step-by-Step Guide to the CPUC's CPCN Application Process for Utility Construction Transmission Projects
5.	Exhibit No. SDG-4	SDG&E Letter to the CPUC regarding concerns with the CPCN Process (September 9, 2015)

6. Exhibit No. SDG-5 List of Anticipated Permits, Authorizations and Requirements for the Project

Concurrently with this electronic filing, SDG&E is submitting by overnight mail a check in the amount of $24,730.00 for the filing fee for this Petition.

VI. CONCLUSION

WHEREFORE, SDG&E respectfully requests that the Commission issue a declaratory order authorizing SDG&E to recover 100 percent of all prudently-incurred development and construction costs if SDG&E is required to abandon or cancel the Project, in whole or in part, for reasons beyond SDG&E's control.

SDG&E understands that such cost recovery is subject to SDG&E demonstrating in a future FPA Section 205 filing that the costs were prudently incurred.

Respectfully submitted,

/s/ Georgetta J. Baker

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Attorney for:
San Diego Gas & Electric Company

September 23, 2015

ATTACHMENT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. EL15-___-000

NOTICE OF PETITION FOR DECLARATORY ORDER

(September__, 2015)

Take notice that on September 23, 2015, San Diego Gas & Electric Company (SDG&E), pursuant to Rule 207 of the Rules of Practice and Procedures of the Federal Energy Regulatory Commission (FERC or Commission), 18 CFR 385.207, section 219 of the Federal Power Act, 16 U.S.C. 824(s), and Order No. 679,[1] San Diego Gas & Electric Company filed a petition for declaratory order requesting authorization of incentive treatment for the South Orange County Reliability Enhancement Project (Project). SDG&E requests incentive rate treatment for application to the Project that will authorize recovery of one hundred percent of all prudently-incurred development and construction costs if the Project is abandoned or cancelled, in whole or in part, for reasons beyond SDG&E's control.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for electronic review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC

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[1] Promoting Transmission Investment through Pricing Reform, Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) ("Order No. 679"), order on reh'g, Order No. 679-A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 ("Order No. 679-A"), order on reh'g, 119 FERC ¶ 61,062 (2007).

Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on _______.

Nathaniel J. Davis, Sr.,
Deputy Secretary

Exhibit No. SDG-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. EL15-___-000

PREPARED DIRECT TESTIMONY OF
DAVID L. GEIER ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

Q1. Please state your name and business address.

A1. My name is David L. Geier. My business address is 8330 Century Park Court, San Diego, California 92123.

Q2. By whom and in what capacity are you employed?

A2. I am employed by San Diego Gas & Electric Company ("SDG&E") as its Vice President – Electric Transmission and System Engineering.

Q3. What are your duties and responsibilities?

A3. In my present position I oversee the planning, design and engineering of SDG&E's distribution, transmission and substation facilities. I am also responsible for operating the transmission grid.

Q4. Please describe your educational background.

A4. I hold a Bachelor of Science Degree in Electrical Engineering and Power Engineering curriculum from the University of Illinois, Urbana. I also hold a Master of Science Degree in Electrical Engineering and Computer Engineering Curriculum from San Diego State University. I am a registered professional engineer in California.

Q5. Please state your work experience prior to the work you are doing today.

A5. I have held several previous management positions at SDG&E, including director of electric grid and distribution services, manager of direct access implementation, and supervisor of several SDG&E operations and facilities. Before joining SDG&E in 1980, I worked for Wisconsin Electric Power Company in Milwaukee.

Q6. Have you ever testified before the Federal Energy Regulatory Commission ("Commission" or "FERC")?

A6. No, I have not.

Q7. What is the purpose of your Prepared Direct Testimony?

A7. The purpose of my testimony is to support the abandoned project cost recovery incentive that SDG&E is requesting in its Petition for Declaratory Order for the South Orange County Reliability Enhancement ("SOCRE") Project ("Project" or "SOCRE Project"). I will first describe SDG&E and provide an overview of the SOCRE Project, including its purpose and need. I will then describe the key features of the Project, including how it best addresses identified reliability concerns and the California Independent System Operator Corporation's ("CAISO") selection and approval process for the Project. Next, I will briefly explain the lengthy and complex state regulatory approval process needed to construct the Project and the related regulatory and litigation risks that are outside of SDG&E's control. Finally, I will explain why granting the requested incentive to recover 100 percent of the costs of the Project if SDG&E is forced to abandon or cancel the Project for reasons beyond its control ("Abandonment Incentive") is appropriate and consistent with Commission precedent and policy:

- the Project was identified by the CAISO in its Board-approved 2010-2011 Transmission Plan as necessary to address the reliability concerns in southern Orange County, and
- SDG&E has satisfied the nexus test in that the requested Abandonment Incentive is narrowly drawn to reflect the risks and challenges of the Project.

Q9. Are you sponsoring any exhibits?

A9. Yes. I am sponsoring the following exhibits.

- Exhibit No. SDG-1 Prepared Direct Testimony of Dave Geier
- Exhibit No. SDG-2 Excerpts from the CAISO 2010-2011 Transmission Plan (issued May 18, 2011)
- Exhibit No. SDG-3 A Step-by-Step Guide to the California Public Utilities; Commission ("CPUC") Certificate of Public Convenience and Necessity ("CPCN") Application Process for Utility Construction Transmission Projects
- Exhibit No. SDG-4 SDG&E Letter to the CPUC Regarding the CPCN Process (September 9, 2015)
- Exhibit No. SDG-5 Anticipated Permit, Approval, and Consultation Requirements for the Project

Q10. Are you SDG&E's only witness in this proceeding?

A10. Yes.

Q11. Please describe SDG&E.

A11. SDG&E is a California public utility corporation with its principal place of business at 8330 Century Park Court, San Diego, California. SDG&E is engaged in the transmission, distribution, and sale of energy services to approximately 3.5 million consumers in San Diego and Orange Counties, California, pursuant to regulation by the

Commission and by the CPUC. SDG&E is a Participating Transmission Owner, as that term is defined in the FERC Tariff of the CAISO, and has transferred operational control of its transmission system to the CAISO.

Q12. Please briefly describe the SOCRE Project, as proposed by SDG&E.

A12. In a nutshell, SOCRE is a reliability Project, estimated to cost approximately $350-400 million. The Project is necessary for two reasons; it will permit SDG&E to (1) comply with the mandatory and enforceable reliability standards of the North American Electric Reliability Corporation ("NERC") and directives and reliability standards of the CAISO and (2) increase electric network reliability and reduce the risk of a potential widespread outage affecting all of SDG&E's customers and substations in the southern Orange County area. SDG&E's southern Orange County service area, located at the northern end of SDG&E's service territory, has more than 129,000 electric customer accounts (including approximately 300,000 consumers). This represents approximately 10% of SDG&E's total customer load (approximately 500 megawatts).

Q13. Please elaborate.

A13. Currently, the southern Orange County customers are served by a 138 kV system sourced from a single 230 kilovolt ("kV") to 138 kV substation. As a result of that single source, southern Orange County customers are at risk of prolonged outages or other disruptions should problems occur at this substation. Such outages could impact public safety, such as health care, public schools, police and fire response, traffic signals, access to telecommunications, and the supply of fresh water and treatment of wastewater. The SOCRE Project would mitigate the risks by, among other things, providing a second independent 230 kV source to southern Orange County at the proposed rebuilt Capistrano Substation.

Q14. How will the SOCRE Project address the NERC reliability requirements referenced above?

A14. The SOCRE Project, as proposed by SDG&E, allows SDG&E to comply with the NERC Reliability Standards by avoiding the need to interrupt electric service to some of its customers in southern Orange County following loss of a single bus element, circuit breaker, or multiple lines or transformers to ensure that the rest of the system remains within applicable facility ratings. The SOCRE Project also allows SDG&E to comply with NERC Reliability Standards during necessary maintenance events. In addition to meeting these mandatory requirements, the SOCRE Project also mitigates numerous other contingencies under which SDG&E would have to interrupt electric service to its customers, and mitigates the risk of southern Orange County being reliant on power from a single substation. The SOCRE Project is designed to bring the system into compliance with FERC's requirements, and to avoid the unnecessary loss of electric service to customers.

Q15. Please continue.

A15. NERC Reliability Standard TPL-001-04 requires the system to be stable and within applicable facility ratings after, among other contingencies, loss of a single bus element, circuit breaker, or multiple lines or transformers. Planning studies performed by SDG&E and the CAISO technical staffs indicate that the existing infrastructure in southern Orange County will be out of compliance with FERC's standards in 2020. This means that the system is expected not to be stable and will not remain within applicable facility ratings upon the loss of two transmission lines at that time. This would lead to controlled load shedding, *i.e.*, disconnection of customers from electric service.

Q16. Please describe the key features of the Project that the CAISO approved.

A16. The Project requires SDG&E to rebuild [and upgrade] its existing 138/12- kV Capistrano Substation in the City of San Juan Capistrano with a new 230/138/12-kV substation called, "San Juan Capistrano Substation." SDG&E will also replace an existing 138 kV transmission line (T13825) with a new double-circuit 230-kV transmission line to connect the proposed San Juan Capistrano Substation to Talega Substation in San Diego County, east of the city of San Clemente. The addition of the proposed 230 kV double-circuit extension would bring a new 230 kV transmission source into southern Orange County. More particularly, the primary components of the Project would include:

1. Rebuilding and upgrading the 138/12-kV 60-megavolt ampere (MVA)[1] air-insulated Capistrano Substation as a 230/138/12-kV 784-MVA gas-insulated substation that would be named San Juan Capistrano Substation;
2. Replacing a single-circuit 138-kV transmission line between the applicant's Talega and Capistrano substations with a new double-circuit 230-kV transmission line (approximately 7.8-miles long);
3. Relocating several transmission line segments (approximately 1.8 miles, total) adjacent to Talega and Capistrano substations to accommodate the proposed Capistrano Substation expansion and new 230-kV line; and
4. Relocating several *distribution line*[2] segments (approximately 6 miles) into new underground *conduit*[3] and onto overhead structures, some existing and some new, located between the Capistrano Substation and the Prima Deschecha Landfill.

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1 Substation capacity is typically expressed in terms of MVA for an alternating current (AC) electrical system.

2 D*istribution lines* are defined as electrical lines that operate at voltages below 50 kV.

3 The term *conduit* refers to protective tubing through which electrical transmission and distribution cables would be installed. Polyvinyl chloride conduit is typically used for power line installations.

The Project does not require the utility to acquire substantial new rights-of-way.

Q17. Why is it significant that the Project does not require the acquisition of substantial new rights-of way?

A17. It's significant because, not only does the Project address the reliability concerns that the CAISO identified in its 2010-2011 Transmission Plan, but the Project also benefits consumers in the immediate vicinity of the Project by using existing rights-of-way and avoiding the need to take private property and minimizing both permanent and temporary, construction-related environmental impacts. The underground segment benefits consumers in the vicinity by potentially eliminating any long-term visual and environmental impacts other than potential traffic disruptions during construction. Further, because the Project also involves replacing existing wood structures with new steel structures, the result is a reduction in potential fire risk and improved fire resistance. This makes not only the new structures more reliable than the structures they will replace, but also the wires they support, which is a benefit that all of SDG&E's customers will enjoy. I will revisit this issue later in my testimony.

Q18. How long as SDG&E been working on securing the necessary approvals to move forward on the SOCRE Project?

A18. SDG&E has been seeking to address reliability issues in southern Orange County at least since 2008. After careful technical review and evaluation of several alternatives in its annual transmission planning process, the CAISO approved the SOCRE Project as the most effective, feasible solution to address the identified reliability issues in its 2010-2011 Transmission Plan. The CAISO made this assessment after applying the Reliability Standards adopted by the NERC and approved by the Commission, pursuant to Section 215 of the Federal Power Act, as well as its own Planning Standards reflected in its

FERC-approved tariff. The CAISO Board approved the Project on May 18, 2011, with an In-Service Date ("ISD") of June 2015. As noted, the Project was included in the CAISO's 2010-2011 Transmission Plan, which is attached to my testimony as Exhibit SDG-2.

Q19. Please describe the CAISO's transmission planning process.

A19. The CAISO's transmission planning process is an open and non-discriminatory regional transmission planning process that considers and evaluates projects for reliability and/or congestion. The Commission has approved the CAISO's transmission planning process. The planning process consists of three phases which collectively run for a period of approximately two years. The CAISO starts a new two-year process annually. This means that at any given time, more than one "annual" process is ongoing, but at different phases of the process. The three phases are described in Exhibit No. SDG-2 at 16-23. The transmission planning process culminates in the publication of Board-approved Transmission Plans for specified periods that set forth the projects the CAISO has selected to meet reliability and/or congestion issues identified in the applicable transmission planning process. The CAISO approved the selection of the SOCRE Project in its 2010-2011 Transmission Plan as necessary to address the reliability issues in southern Orange County.

Q20. In approving the Project, did the CAISO identify reliability benefits of the Project?

A20. Yes. SDG&E and the CAISO performed studies identifying the need for transmission upgrades in the southern Orange County bulk power system to meet NERC reliability criteria set forth in Transmission Planning Standard, TPL-001-4.[4] Specifically, the CAISO identified that by 2020, the southern Orange County area will be susceptible to multiple NERC Category C overloads, *i.e.*, overloads caused by the loss of a single bus element, circuit breaker, or multiple lines or transformers.[5] The CAISO directed SDG&E to add a second 230 kV connection to the bulk power system for the southern Orange County area to avoid risks to customer service and to satisfy NERC requirements for Category C contingencies.

Q21. Please describe the studies the CAISO performed.

A21. The CAISO performed detailed studies of the southern Orange County area as a part of the 2010-2011 Transmission Planning Process. As stated in the CAISO's 2010-2011 Transmission Plan:[6]

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[4] The NERC is the entity responsible for developing, among other things, mandatory electric transmission planning reliability criteria. These criteria consider four different categories of system conditions, or "contingencies," referred to as Categories A-D. These categories may be summarized as follows: Category A – Normal conditions with all facilities in service; Category B – Loss of a single element (line, transformer, or generator) generally referred to as an N-1 condition; Category C – Loss of a single bus element, circuit breaker failure, or loss of multiple lines or transformers, generally referred to as an N-1-1 or N-2 condition and Category D – An extreme system event, such as loss of multiple system elements, loss of an entire voltage level at a single substation, and so forth. TPL-001-4 uses different designations for the same system conditions. My testimony focuses on Category C contingencies.

[5] Category C contingencies are defined by NERC transmission planning standard TPL-003-0b Table I. This standard was superseded by NERC standard TPL-001-4 effective January 1, 2015. In the currently- effective standard, the contingency types defined as Category C have been replaced with Categories P2, P4, P5, P6, and P7. However, because the functional definition for each contingency type has not changed, this testimony will continue to use the term Category C, for convenience.

[6] CAISO 2010-2011 Transmission Plan, issued May 18, 2011, p. 209.

> Power flow study results of the peak load scenarios identified numerous facility loadings that exceeded their rated capabilities under Category C contingencies beyond 2015. All three alternatives considered here can mitigate the loading issues for Category C contingencies. In order to determine the most effective alternative, aspects beyond just the NERC compliance were taken into consideration. Historical data for bus outages at Talega and planned outages that put load at risk was accumulated and examined. It was quite evident that the lack of second source into southern Orange County puts more load at risk than the Category C issues noticed in the reliability assessment of the system. Hence, in order to improve the overall reliability of this system, it is important to bring another source into this area. Thus, the CAISO's studies determined that introducing a second source into southern Orange County best addressed the loading issues for Category C contingencies.

Q22. Did the CAISO consider alternatives to the Project?

A22. Yes. The CAISO identified two alternatives to the Project that would also meet NERC reliability standards. The CAISO rejected those other alternatives due to a combination of cost and effectiveness at improving system reliability. The three alternatives that the CAISO considered were as follows:

- Alternative 1 – The Project, with a second 230 kV line extending from Escondido Substation to San Juan Capistrano Substation.
- Alternative 2 – Reconductoring the existing 138 kV southern Orange County system, without the addition of a second 230/138 kV source.
- Alternative 3 – The Project, as proposed by SDG&E and described above.

In concluding that the Project, as proposed by SDG&E, is preferable to the alternatives it considered, the CAISO stated:

> The project submitted by SDG&E (Alternative 1) aims to achieve [adding an additional bulk power connection to the South Orange County area], but Alternative 3 achieves similar reliability performance at a considerably lower cost. Alternative 2 mitigates the Category C issues through 2021, but fails to deliver another source into this area and hence fails to address the risk of load shedding due to contingencies at Talega. Alternative 3 [the Project] provides another source into southern Orange

> County system at very little extra cost compared to Alternative 2. It also offers a potential for future upgrades in case of further load growth. After a comprehensive analysis, the ISO staff concluded that SOCRUP Alternative 3 as the most effective, feasible solution to meet the reliability needs of southern Orange County area. Therefore, the ISO has found that the SOCRUP Alternative 3 project is needed to address the reliability concerns in the southern Orange County area.[7]

Here, the CAISO once again determined that a second bulk power connection to the high-voltage network was necessary to ensure reliable electric service for southern Orange County and that the Project, which the CAISO designated as SOCRUP Alternative 3, was the most effective, feasible solution to meet the reliability needs of southern Orange County area.

Q23. How will the Project be managed on an ongoing basis?

A23. SDG&E will own the Project and be responsible for maintaining the Project. The CAISO will have operational control of the project as the system operator, under the CAISO's FERC-approved CAISO tariff and the FERC-accepted Transmission Control Agreement between the CAISO and SDG&E.

Q24. How will the costs of this Project be recovered?

A24. SDG&E will recover the costs of the Project in the appropriate rate filing. Currently, SDG&E has a formula rate mechanism, the Fourth Transmission Owner Formula, or TO4 Formula. The TO4 Formula will end on December 31, 2018. It is not clear at this time whether SDG&E will file a new formula rate mechanism or use a traditional cost of service rate mechanism, using Period 1 and Period 2 cost data. In any event, SDG&E will include the related costs of the Project in a subsequent Base Transmission Revenue Requirements ("BTRR") rate filing. The High Voltage cost components of the BTRR

[7] CAISO 2010-2011 Transmission Plan, issued May 18, 2011 at 209.

will be recovered *via* the CAISO's Transmission Access Charge mechanism where costs are allocated to consumers based on the load ratio share for each CAISO Load Serving Entity.

CPCN PERMITTING PROCESS IS LENGTHY AND COMPLEX

Q25. Mr. Geier, why does the SOCRE Project requires a CPCN from the CPUC to construct the Project?

A25. A CPCN tends to be required for the largest, most costly, most complex and most contentious projects that SDG&E is developing at any given time. As a general matter, obtaining a CPCN is a lengthy and complex process. Exhibit No. SDG-3 contains a Step-by-Step Guide to the CPCN application process. I note here that SDG&E's application for a CPCN to construct SOCRE has been pending for over three years, since May 2012. SDG&E has been so concerned with the delayed CPUC action on the CPCN application that on September 9, 2015, SDG&E sent a letter to the President of the CPUC, which I co-signed, voicing its concern with the CPCN process. The letter is attached as Exhibit No. SDG-4.

In that letter, SDG&E noted the three-year delay and expressed concerns about how the environmental review and application have been processed. Specifically, the CPCN application was filed on May 18, 2012 and deemed complete in January 2013. The California Environment Quality Act ("CEQA") scoping meetings and comment period were complete by February 2013. However, CEQA Staff did not circulate a Draft Environmental Impact Report ("DEIR") until two years later, in February 2015. Six months later, in August 2015, CEQA Staff recirculated the DEIR with new proposals. It appears that the hearing will be scheduled for November 2015. In the letter, SDG&E requested assurance that the hearing would move forward and a final decision on the SOCRE Project would be issued in the first quarter 2016. The timing is critical if SDG&E is to have any realistic opportunity of constructing the Project that the CAISO selected in its Board-approved 2010-2011 Transmission Plan as necessary to comprehensively address the identified reliability problems for southern Orange County.

Q26. Please continue describing the CPCN process.

A26. The CPUC's General Order 131-D governs certain construction activities by CPUC-jurisdictional public utilities and requires that SDG&E obtain a CPCN before it may begin building the Project. As a general matter, the formal start of the process is the filing of the CPCN application, which includes a Proponent's Environmental Assessment ("PEA"). It is important to note that applicants for a CPCN often are required to provide supplemental information before the CPUC will deem the application complete. Moreover, while the submission of an application for CPCN is the formal start of the permitting process from the agency's perspective, from an applicant's perspective, the process starts long before that milestone.

Q27. Please explain this latter point.

A27. The PEA identifies alternatives the applicant considered, the applicant's rationale for the chosen alternative, and a host of environmental and other information concerning the proposed project. For a Project such as this one, it is critically important for the developer to identify, to the best of its ability, a route that avoids, or at least minimizes, adverse environmental, community, and cultural impacts, while preserving the project's technical feasibility and economics. This is a challenging process that often involves a series of tradeoffs because, for instance, the strictly least-cost route may have unacceptable community or environmental impacts. Thus, the preparation of an application for a CPCN presents many challenges and involves careful consideration of a myriad of factors over a period of months or even years prior to the submission of the application.

Q28. What does the CPUC consider in determining whether to grant a CPCN?

A28. The CPUC analyzes a proposed project from two perspectives: (1) environmental and (2) purpose and need. The environmental analysis is performed under CEQA. As lead agency under CEQA, the CPUC will evaluate the Project's environmental impacts and in so doing will give consideration to alternatives to the Project. In both analyses, the CPUC seeks input from the public and other agencies and considers alternatives to the proposed project. Based on its findings, the CPUC could disapprove, approve or modify a proposed project, including imposing mitigation measures for any significant environmental impacts.

Q29. Is SDG&E's CPCN application for the Project being contested?

A29. Yes, several parties have protested the CPCN application. Moreover, as noted, the CEQA Staff has circulated two DEIRs – one in February and the other in August 2015 (three years after the CPCN application was filed). SDG&E is in the process of evaluating the original and recirculated DEIRs.

Q30. You mentioned that SDG&E will need minimal amounts of new rights-of-way to construct the Project as proposed. Do you believe that enhances the probability that SDG&E will obtain a CPCN to construct the Project?

A30. I do.

Q31. Please explain.

A31. First and foremost, SDG&E designed the Project in order to minimize, to the extent we could, risks to the Project's being in service on the timeframe required by the CAISO. One of the most important, if not the most important, of SDG&E's design choices was a route that required minimal new rights-of-way, because obtaining new or expanded existing rights-of-way is very difficult and costly. Moreover, it frequently involves exercise of eminent domain, and at a minimum adds litigation risk and quite likely delays in Project construction and in-service date. Avoiding litigation and delays associated with rights-of-way acquisition allows the Project to be placed in service earlier than would otherwise be possible. Additionally, by minimizing the need to acquire new rights-of-way, the scope of required environmental reviews is reduced. Reducing the scope of environmental reviews increases the probability of obtaining the necessary CPCN to construct the Project.

But the mere fact of having existing rights-of-way does not mitigate all routing-related risks. Rather, and more significant in my judgment are the facts that SDG&E will use mostly existing right-of-way that already have existing overhead electric facilities located in them and existing roadways underneath which the underground facilities will be located. While challenging from a project design perspective, utilization of existing rights-of-way that already have facilities in place reduces environmental impacts as compared to a route utilizing undisturbed land. SDG&E believes that its successful identification of such a route should translate into a greater probability of achieving the necessary permits.

While rights-of-way issues obviously are not the only ones that command the attention of ratepayer advocates and intervenors in CPCN proceedings, they are often a source of controversy. Accordingly, SDG&E's design choices – avoiding undisturbed lands and minimizing new rights-of-way acquisitions – were intended to minimize the need to acquire property and thereby enhance the probability of successfully obtaining a CPCN for the Project.

Q32. Is it certain that SDG&E will receive the necessary CPCN to construct the Project?

A32. No. Although the CAISO has selected the Project as the most effective, feasible solution to meet the identified reliability needs of southern Orange County, there is no guarantee that the CPUC will issue a CPCN. Moreover, even if SDG&E receives the necessary CPCN, that does not guarantee that SDG&E will be able to develop the Project.

Q33. Why?

A33. There are a range of possible outcomes from the CPUC permitting process, including the CPUC authorizing SDG&E to construct the Project along the route proposed by the utility. On the other hand, the CPUC could decline to grant SDG&E's application entirely, or could grant it on terms that are not reasonably acceptable to the Company. Still other possible outcomes are that the CPUC could permit the Project but require the

Company to use an alternate routing, or require SDG&E to implement onerous environmental mitigations.

If the CPUC directs that SDG&E utilize a route segment for which we do not currently have rights-of-way, SDG&E would be required to obtain new rights-of-way in order to construct the Project. Note that the CAISO approved the SOCRE project in 2011 with an ISD of 2015. The earliest possible ISD is now 2020. However, the risk and delay associated with obtaining new rights-of-way may render the 2020 ISD infeasible unless SDG&E is required to adopt less-efficient back-stop mitigation measures. In other words, SDG&E's development risk is substantial and can increase for reasons beyond SDG&E's control.

Q34. Please describe the less-efficient or less-effective back-stop mitigation measures you referred to above.

A34. Among the less-efficient or less-effective mitigation measures are:

1) Involuntary shedding of customer load to reduce post-contingency overloads. In some cases, load shedding may have to be done pre-contingency in order to prevent exceeding the applicable rating of a facility.

2) Piecemeal reconductoring or replacement of lines or equipment that would not have to be done if the SOCRE Project was approved.

3) Purchasing or condemning additional land or ROW that would not be necessary if the SOCRE Project were approved, as proposed.

None of these mitigation measures in and of themselves will provide the second connection to the high-voltage bulk power network that was identified as necessary by the CAISO when the SOCRE Project was approved. These mitigation measures, therefore, would fail to meet the objectives of the SOCRE Project even if they would meet the minimum requirements of the mandatory reliability criteria.

Q35. Apart from the CPUC, will SDG&E require permits or other authorizations from any other agencies in order to construct the Project?

A35. Yes. SDG&E anticipates it will be required to meet other Federal, State and Local permit, approval and consultation requirements for the Project. Exhibit No. SDG-5 lists anticipated permits, authorizations and requirements for the Project. Notably, SDG&E will require review from the military to construct the portion of the Project located on Camp Pendleton grounds, and such review could implicate the National Environmental Policy Act.

Q36. Given the foregoing, what do you conclude about the probability that SDG&E will be permitted to construct the Project, as approved by the CAISO?

A36. SDG&E has invested and will continue to invest considerable resources toward this project and the Company's design choices were intended to achieve the highest probability that the Project would be permitted and constructed. In my opinion, the merits of the Project are compelling and the need is urgent. I am confident that there is a clear and present need for the Project and that all of the affected regulatory agencies that will oversee the Project will come to that conclusion and that SDG&E ultimately will receive all of the regulatory approvals it needs to construct this important project.

However, the decision whether SDG&E will be permitted to build the Project is not in SDG&E's hands. SDG&E has no guarantee that it will be permitted to construct the Project at all, let alone that the Project will follow the specific route recommended by SDG&E or on a timeframe that addresses the reliability needs of SDG&E's customers in southern Orange County. Moreover, there is always the possibility of further regulatory or judicial action that would frustrate SDG&E's ability to construct the Project in a timely and cost-effective manner.

THE ABANDONMENT INCENTIVE IS WARRANTED TO MITIGATE THE RISKS AND CHALLENGES OF THE PROJECT

Q37. Are you familiar with the Commission's policy governing the Abandonment Incentive?

A37. Yes. I understand that under Order No. 679,[8] an applicant may seek incentive rate treatment for a transmission infrastructure investment by showing that "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion."[9] I also understand that the applicant can meet that standard by showing that "the transmission project results from a fair and open regional planning process that considers and evaluates the project for reliability and/or congestion…."[10] That's called a rebuttable presumption. Finally, I understand that an applicant seeking an incentive must demonstrate a nexus between the incentives requested and the proposed investment, including showing that the requested incentives address project-specific risks and challenges.

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8 *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) ("Order No. 679").

9 Order No. 679 at P 76.

10 *Id*.

In a subsequent order, Order No. 679-A,[11] the Commission refined the nexus test by requiring a showing that the total package of incentives is rationally tailored to the risks and challenges of constructing new transmission.

Finally, in the Policy Statement,[12] the Commission reaffirmed its policy of awarding risk-reducing incentives, including, among other things, recovery of prudently incurred costs if the project is abandoned. The Commission's Policy Statement notes that "recovery of 100 percent of prudently incurred costs of transmission facilities that are abandoned for reasons beyond the applicant's control…reduce the financial and regulatory risks associated with transmission investment."[13] The Policy Statement also noted that it is no longer necessary for an applicant to rely on whether the Project is "routine/non-routine" to meet the nexus test.[14]

In my view, as discussed more fully below, granting the Abandonment Incentive for the Project is appropriate under Order Nos. 679 and 679-A, and under the Policy Statement.

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[11] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 ("Order No. 679-A").

[12] Policy Statement on Promoting Transmission Investment through Pricing Reform, 141 FERC ¶ 61,129 (2012) ("Policy Statement").

[13] Policy Statement at P 11.

[14] *Id*. at P 10.

Q38. Has the Commission recently determined that SDG&E's Sycamore-Peñasquitos transmission line project ("Sycamore-Peñasquitos Project") met the rebuttable presumption because it had been approved in the CAISO's transmission planning process?

A38. Yes. The CAISO approved the Sycamore-Peñasquitos Project in its 2012-2013 Transmission Plan. In *San Diego Gas & Electric Company*,[15] the Commission stated that "because the [Sycamore-Peñasquitos Project] is necessary to ensure grid reliability and was selected in a Commission-approved regional transmission planning process, the Project meets the rebuttable presumption and satisfies the []requirements of FPA section 219."[16]

Q39. Following that rationale, do you believe the SOCRE Project also meets the rebuttable presumption?

A39. Yes, the CAISO approved SOCRE Project was approved in the CAISO's 2010-2011 Transmission Plan because the CAISO determined that the Project: (1) "is important to bring another source into this area" to improve reliability[17] and (2) "is the most effective, feasible solution to meet the reliability needs of Southern Orange County area."[18] Since the CAISO expressly approved the SOCRE Project to address reliability needs, the Project meets the requisite rebuttable presumption.

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[15] In *San Diego Gas & Electric Co*., *Order Granting in Part, and Denying in Part, Petition for Declaratory Order*, 151 FERC ¶61, 011 (2015) (*SDG&E Order*), the Commission granted SDG&E's request for the abandoned project cost recovery incentive.

[16] *Id*. at P 30.

[17] Transmission Plan at 210.

[18] *Id*.

Q40. In your view, is the requested Abandonment Incentive for the Project consistent with the Policy Statement?

A40. Yes, the Abandonment Incentive will reduce the financial and regulatory risks associated with transmission investment if SDG&E if forced to cancel or abandon the Project, in whole or in part, due to reasons beyond its control.[19] Moreover, although the routine/non-routine is no longer required for the nexus test, I note that most SDG&E's transmission projects do not require CPCN authorization. Those that do require CPCN authorization, like the SOCRE Project, tend to be the largest, most costly, most complex or most contentious projects that SDG&E is developing at any given time.

Q41. How did the Commission apply the nexus test for the Sycamore-Peñasquitos Project Abandonment Incentive and should it be applied similarly to the SOCRE Project?

A41. The Commission found that SDG&E had met the nexus requirement and that the requested abandoned plant cost recovery incentive was warranted. There, the Commission stated:

> The Commission finds that SDG&E has demonstrated that the requested Abandonment Incentive is warranted. The Abandonment Incentive appropriately addresses the risks and challenges specific to the Project, such as regulatory and litigation risk, and the challenge of meeting CAISO's timeline. These risks and challenges are outside of SDG&E's control and could potentially lead to the abandonment of the Project. Therefore, we grant SDG&E's request for an Abandonment Incentive, subject to SDG&E's filing under section 205 of the FPA for recovery of abandonment costs. SDG&E must propose in a future section 205 filing a just and reasonable rate to recover such abandoned plant costs.[20]

The same result is equally applicable to the SOCRE Project. As discussed below, the SOCRE Project faces similar regulatory and litigation risks associated with the CPCN

[19] Policy Statement at P 11.

[20] *Id*. at P 31.

permitting processes at the CPUC. SDG&E's CPCN application has been pending since 2012 and it is contested. Unless and until the CPUC approves a Project that will meet SDG&E's and the CAISO's reliability objectives, SDG&E remains subject to regulatory and litigation risks that the Abandonment Incentive is intended to address.

Q42. You have stated generally, that SDG&E is entitled to the Abandonment Incentive. Can you provide more detail as to why the requested incentive is warranted?

A42. Yes. SDG&E has already expended substantial resources, both direct spending and internal labor, in order to develop a Project that had the greatest likelihood of satisfying the reliability requirements of SDG&E's customers in south Orange County, without assurance of cost recovery for these development costs, because of its obligation to ensure ongoing safe and reliable service. The Abandonment Incentive is important from a financial perspective and is tailored to the risks and challenges that SDG&E will face in developing this Project.

Q43. Can you quantify the costs SDG&E has incurred to date for this Project?

A43. Thus far, SDG&E has incurred in excess of $31 million toward the development of the Project through June 2015. By the end of calendar year 2015, SDG&E anticipates that figure will approach $35 million.

Q44. What is the value of abandoned plant cost recovery to SDG&E?

A44. As a general matter, assurance that prudently incurred costs can be recovered should abandonment be required for a reason beyond the developer's control, supports investment of significant equity capital on project development. Development activities include permitting and environmental studies, detailed engineering and design, contracting labor and materials, and, on certain projects, acquiring right-of-way. Without abandoned plant cost recovery protection, developers are at risk for the costs of these development activities. However, the ultimate decision on whether transmission projects that require regulatory approvals can proceed rests with permitting agencies and regulatory bodies that are not necessarily under an obligation to approve or act timely on a proposed project or with commercially acceptable conditions.

In this case, SDG&E has already begun devoting substantial resources to maximize the chances of achieving a Project ISD that satisfies the CAISO's desire to have the Project in service as soon as is reasonably possible and will allow the Project to be ready for construction upon receipt of all necessary approvals. As noted above, the CAISO approved the SOCRE Project in its 2010-2011 Transmission Plan with an initial in-service date of 2015 to address potential Category C contingencies, forecast to arise as early as 2016. Those contingencies might be resolvable through load shedding; however, Category C contingencies forecast for 2020 would be more problematic to address absent implementation of the SOCRE Project. Clearly, the CAISO would prefer that this Project be completed as soon as is reasonably possible to limit the risk of involuntary shedding of customer load.

SDG&E believes it has proposed a Project that should receive all necessary regulatory approvals and, accordingly, I do not expect SDG&E to need to abandon the Project. Nevertheless, the possibility remains that events may occur as a result of the regulatory and litigation risks that are beyond SDG&E's control, requiring abandonment of the Project.

Q45. Please identify some reasons why SDG&E, despite its best efforts, might be forced to abandon the Project.

A45. An inability to obtain the aforementioned approvals or to implement environmental mitigation measures could result in Project cancellation. Further, subsequent regulatory or judicial actions could result in SDG&E needing to abandon the Project even if SDG&E receives all necessary approvals. If the timing of obtaining approvals or implementing required environmental mitigation measures does not allow SDG&E to satisfy the CAISO's desire to have the Project in service as soon as is reasonably possible, the Project's viability could be jeopardized. These kinds of risks--CPCN permitting and siting risks--are the types of "regulatory risk" the abandoned cost recovery incentive was intended to address.

Q46. Does affording SDG&E abandoned cost recovery serve an important public policy objective?

A46. Yes. Allowing for 100 percent abandoned cost recovery for the SOCRE Project, which faces unique challenges and risks as addressed in my testimony, would mitigate the risk of writing off a portion of the Project. This, in turn, would increase the costs of investing in existing and future SDG&E capital projects that must be funded with debt and equity.

Q47. Although SDG&E is not requesting a specific incentive for advanced technologies, will SDG&E use advanced technologies for the Project?

A47. SDG&E will use the following advanced technologies for transmission:

1. LIDAR: LIDAR technology allows airborne surveys of terrain and overhead utility facilities, such as transmission towers and conductors. LIDAR data can be processed and used in the PLS-CADD or other 3D modeling programs, with static features, such as terrain, used as vectors to enable more efficient subsequent analyses focusing on

vegetation and power line rating. For purposes of visualization, 3D models generated in PLS-CADD can be output to Google Earth layers or GIS Shapefiles.

2. HELICOPTERS: Use of helicopters during construction will: (1) decrease construction time by providing for the expeditious delivery of materials and supplies as needed, (2) minimize vehicle traffic within the Project alignment and (3) increase SDG&E's ability to monitor safety conditions on a real time basis, both in normal and emergency situations.

3. OPTICAL GROUND WIRE (OPGW)/FIBER OPTIC CABLE: A fiber optic system provides a robust infrastructure that enables improved data capacity and transfer rates along the transmission and distribution systems. As the main communication path that controls utility systems, optical cabling allows utilities to monitor power on the line, move power to avoid outages and brownouts, interact with substations and manage normal communications. The Project would have a dual purpose shield wire for all overhead portions of the line known as OPGW which combines the functions of grounding and communications into one wire.

4. GEOPHYSICAL RADAR LOCATING: Ground Penetrating Radar is a new and valuable tool for locating underground facilities in today's complex utility world. It can immediately locate and mark buried service utilities (*e.g*., gas, electric and sewer lines, water lines, storm drains, telecommunication cables) and provides real-time horizontal and vertical position of a wide range of utility structures and buried objects. In developing the Project, SDG&E may utilize GSSI UtilityScan LT for locating underground utilities along Vista Montana and around San Juan Capistrano Substation for the 138kV and 12kV underground exiting the substation.

5. MOBILE DEVICE APPLICATIONS: SDG&E will employ a broad range of applications for mobile devices, such as tablets and smart phones, in connection with environmental, safety, inspection, and other staff monitoring construction activities. The applications will include mapping tools for identifying the locations of project components and reporting forms to record construction progress and document compliance with project requirements. Data collected using mobile devices will be used to update project status and provide documentation of daily field activities

Q48. Will SDG&E use other substation-related advanced technologies for the Project?

A48. Yes. SDG&E will use the following substation advanced technologies:

1. GAS-INSULATED SUBSTATION ("GIS"): GIS technology enables flexible design of the new Capistrano substation while reducing the space required to build-it. GIS technology uses Sulfur Hexafluoride ("SF6") gas as an insulating medium rather than atmospheric air, which has a much stronger dielectric strength, allowing conductor to be spaced closer together without an increased risk of arcing.

2. CONDITION-BASED MONITORING: Substation transformers and circuit breakers are monitored with devices for the purposes of detecting and preventing catastrophic failure and reducing maintenance. Transformer monitors measure and test dissolved gasses in dielectric oil, thermal performance, auxiliary device load, and bushing insulation. These points allow SDG&E's field operations group to detect and repair manufacturer defects that could lead to early failure of transformers on this project. It also allows field crews to quickly repair auxiliary devices that have failed on these transformers, allowing for more operability and increased reliability. Gas circuit breaker monitoring measures SF6 density, operating mechanism timing, and cumulative fault interruption. It reduces maintenance on circuit breakers, while increasing reliability for these devices. Circuit breaker monitoring tells crews when maintenance needs to be performed, rather than them performing it on time-based intervals.

3. SUPERVISORY CONTROL AND DATA ACQUISITION ("SCADA"): SCADA infrastructure increases remote operational control and visibility of the electric grid. SCADA enables centralized operators to remotely see voltage, current, and open/close or alarm status of equipment within a substation. It also allows remote operation of circuit breakers, load tap changers, and other devices. Increased SCADA will be installed on this project to enhance the operational visibility of the Distribution and Transmission infrastructure at the Capistrano substation, which directly increases reliability to customers fed from that station.

CONCLUSION

Q49. Does this conclude your prepared direct testimony?

A49. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	)	Docket No. EL15-___-000

State of California	))))	Affidavit Adopting Prepared Direct Testimony

David L. Geier, being first duly sworn, on oath, says that he is the David L. Geier, identified in the foregoing prepared testimony; that he caused to be prepared such testimony; that the answers appearing therein are true to the best of his knowledge and his belief; and that if asked the questions appearing therein, his answers thereto would under oath, be the same.

David L. Geier

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California)
County of San Diego)

Subscribed and sworn to (or affirmed) before me on this 23rd day of September, 2015, by **David L. Geier**, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

ANNIE V. RUIZ
COMM. #2052917
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jan 18, 2018

Signature of Notary Public

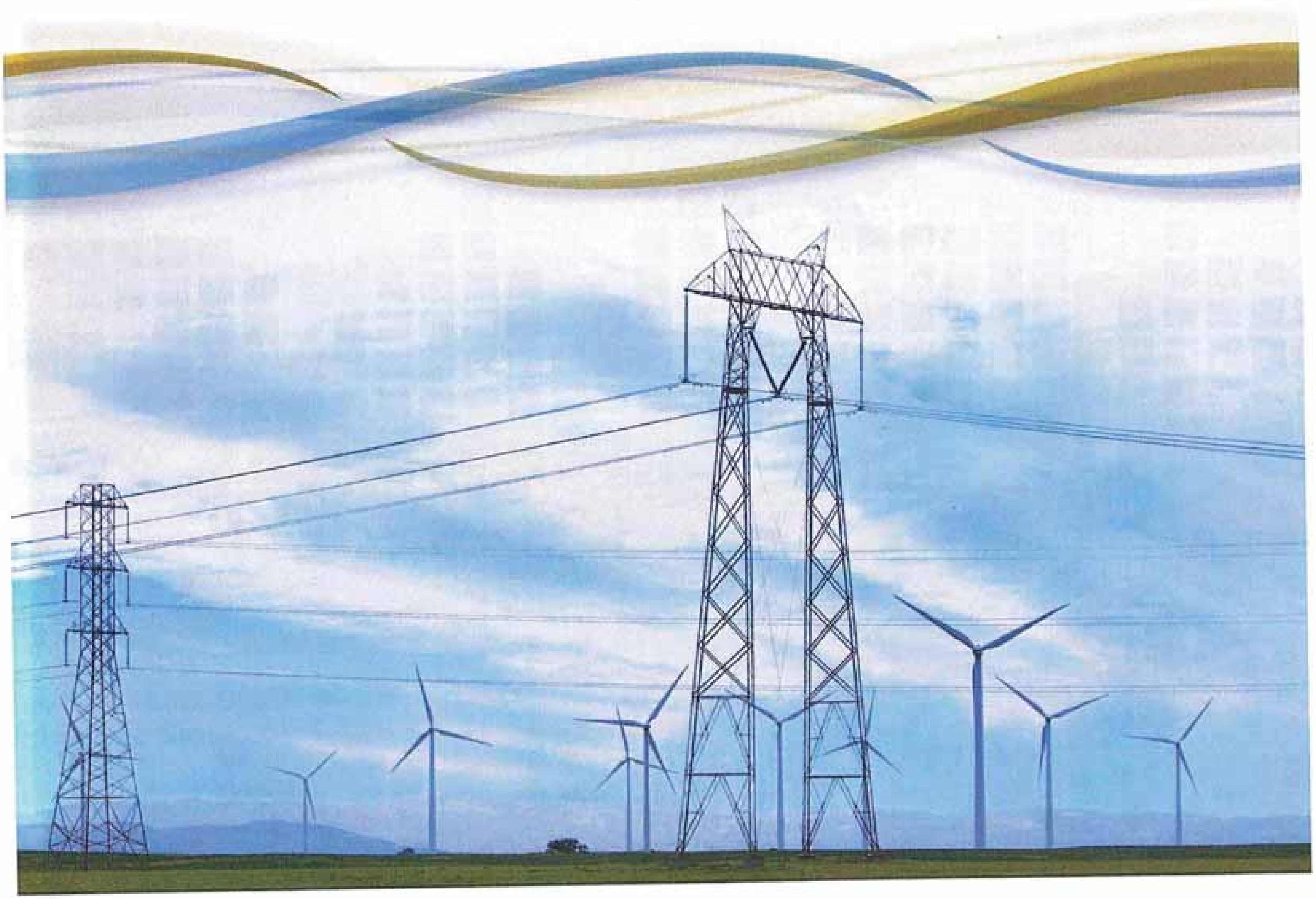
(Seal of Notary)

Exhibit No. SDG-2

California ISO
Shaping a Renewed Future

2010-2011 Transmission Plan

May 18, 2011
Approved by ISO Board of Governors



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Executive Summary

1) Introduction

The 2010/2011 California Independent System Operator Corporation transmission plan presents results from the first cycle of the revised transmission planning process.[1] This ISO transmission plan, which will be updated annually, provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to successfully meet California's policy goals, in addition to examining conventional grid reliability requirements and projects that can bring economic benefits to consumers. In recent years, California enacted policy goals aimed at reducing greenhouse gases and increasing renewable resource development. The state's goal to have renewable resources provide 33% of California's electricity consumption by 2020 has become the principal driver of substantial investment in new renewable generation capacity both inside and outside of California.

The transmission plan describes the transmission necessary to meet the state's 33% RPS goals. Key analytic components of the plan include:

- Identification of transmission needed to support meeting the 33% RPS goals over a diverse range of renewable generation portfolio scenarios, which are based on plausible forecasts of the type and location of renewable resources in energy-rich areas most likely to be developed over the 10 year planning horizon;

- A "least regrets[2]" analysis of transmission infrastructure under development but not yet permitted, as well as policy-driven elements that might be needed to deliver energy from the resources in these portfolios to the ISO grid;

- Evaluation of need for all of the transmission projects submitted into the 2008 and 2009 transmission planning request windows;

- Identification of transmission upgrades and additions needed to reliably operate the network and comply with applicable planning standards and reliability requirements; and

[1] The Revised Transmission Planning Process (RTTP) was filed on June 4, 2010 by the ISO at the Federal Energy Regulatory Commission following a lengthy stakeholder process and approval by the ISO Board of Governors. In an order issued on December 16, 2010, FERC approved the ISO filing subject to certain limited modifications to the ISO tariff, to be effective as of December 20, 2010.

[2] The "least regrets" approach can be summarized as evaluating a range of plausible scenarios made up of different generation portfolios, and identifying the transmission reinforcements found to be necessary in a reasonable number of those scenarios. It is captured in more detail in the ISO tariff, in section 24.4.6.6.

- Economic analysis that considers whether transmission upgrades or additions could provide additional ratepayer benefits.

Our comprehensive evaluation of the areas listed above resulted in the following key findings.

- No new major transmission projects are required to be approved by the ISO at this time to support achievement of California's 33% RPS goals given the transmission projects already approved or progressing through the California Public Utilities Commission approval process because:
  - The major transmission projects already underway accommodate a diverse range of resource portfolios for meeting a 33% RPS goal, including in-state generation, distributed generation, and out of state scenarios;
  - Existing inter-state transmission will have capacity made available as renewable resources displace energy from traditional resources;
  - Approving more transmission under the circumstances and conditions that exist today would increase risk of stranded costs; and
  - The ISO will reassess transmission needs in future annual planning cycles and consider any changed conditions, potential policy changes (e.g., increased emphasis on distributed generation), renewable generation advances utilizing previously approved transmission, and any new factors that may drive future generation development.
- Justification for additional transmission to support out-of-state procurement will need to be addressed through the CPUC renewable energy procurement approval process to determine the specific location, quantity, and type of renewable energy projects.
- Immediate focus now should be on:
  - Obtaining approvals for identified transmission; and
  - Renewable energy procurement
- The ISO evaluated all 41 transmission project proposals submitted in the 2008 and 2009 request windows to determine if they are needed as either policy driven or economically driven transmission projects. One of the projects, reconductoring of the Devers-Mirage 230 kV double circuit line, was found to be needed as a policy driven line to support California's RPS goals.
- The ISO identified 32 transmission projects with an estimated cost of $1.2 billion, as needed to maintain the reliability of the ISO transmission system.

- The ISO performed a transmission congestion study to determine potential areas for transmission reinforcement. These study results led to the detailed evaluation of nine specific congestion mitigation plans. The analyses compared the cost of the mitigation plans to the expected reduction in production costs, congestion costs, transmission losses, capacity or other electric supply costs resulting from improved access to cost-efficient resources and determined that none of the mitigation plans were economically justified.

The finding that no major new transmission projects are needed at this time to support the California's RPS goals reflects years of effort by California state agencies, participants in the Renewable Energy Transmission Initiative, market participants and the ISO that resulted in the approval and ongoing construction of major transmission projects such as Tehachapi and the Sunrise Powerlink. The ISO recognizes, however, that uncertainty remains regarding how California will ultimately meet its 33% RPS goals in terms of the precise locations, resource mix and quantity of renewable energy resources. While this plan shows that the transmission approved to date can accommodate a diverse range of plausible renewable development scenarios, the ISO will continue to work with state agencies and all stakeholders to evaluate development trends and policy directives beginning with next year's planning cycle and will reassess the transmission needs accordingly.

This year's transmission plan is based on the ISO's recently approved transmission planning process, which involved collaborating with the California Public Utilities Commission (CPUC), California Transmission Planning Group (CTPG), and many other interested stakeholders. Summaries of the RTPP and some of the key collaborative activities are provided below. This is followed by additional details on each of the key study areas and associated findings described above.

2) The Revised Transmission Planning Process

A core responsibility of the ISO is to plan and approve additions and upgrades to transmission infrastructure so that as conditions and requirements evolve over time, it can continue to provide a well-functioning wholesale power market through reliable, safe and efficient electric transmission service. Since it began operation in 1998, the ISO has fulfilled this responsibility through its annual transmission planning process. The State of California's adoption of new environmental policies and goals created a need for some important changes to the planning process. In 2009, the ISO initiated a stakeholder process to design the needed changes, and in June 2010 filed tariff amendments with the Federal Energy Regulatory Commission (FERC) to implement the needed changes. The FERC approved RTPP tariff amendments on December 16, 2010, and the amendments went into effect on December 20, 2010.

The RTPP improves upon the prior transmission planning process in several important ways including:

Establishing a new "policy-driven" category of transmission additions and upgrades that are needed to meet state and federal public policy directives and goals;

Managing the risk of stranded investment associated with transmission additions by creating a distinction between category 1 (transmission elements that will be approved as part of the transmission plan) and category 2 (transmission elements that will be re-evaluated in future cycles);

Providing for collaboration with other transmission planners in California in development of a statewide conceptual transmission plan that will serve as an input into the ISO planning process;

Improving coordination between transmission planning and the Generation Interconnection Procedures (GIP);

Providing more opportunities for stakeholder participation and input to the process;

Allowing all interested project sponsors, including independent developers and existing participating transmission owners, an equal opportunity to propose to construct and own policy-driven and economically-driven transmission facilities included in the plan; and

Enabling the ISO to use its planning resources efficiently to develop a comprehensive annual plan that addresses all categories of identified transmission infrastructure needs.

Most of the planning activities and studies reported in this document were performed in 2010, prior to FERC's December approval of RTPP. During that period, the ISO followed the requirements and provisions specified in its tariff for the then-current transmission planning process, but expanded the scope of its analyses to assess the capability of the grid, augmented by the upgrades already in progress or approved, to support the 33% RPS goals. This proactive approach allowed an expedient transition from the previous transmission planning process to RTPP.

One RTPP enhancement is the development of a conceptual statewide plan, which is developed by the ISO in coordination with neighboring balancing authority areas and planning entities and provided to stakeholders for comment and recommendations to be considered in the ISO's comprehensive analysis. Based on the work of CTPG and other data developed by the ISO, a conceptual statewide plan was developed and released by the ISO on January 17, 2011.

3) Collaborative Planning Efforts

Responding to the need for coordinated action, the ISO, utilities, state agencies and other stakeholders worked closely to assess how to meet the environmental goals established by state policy. The collaboration with these entities is evident in the following initiatives.

Renewable Energy Transmission Initiative (RETI)

A joint initiative between the ISO, CPUC, California Energy Commission (CEC), investor-owned and publicly owned utilities and other stakeholders, RETI identified areas in California and neighboring states with concentrations of high-quality renewable resources that could be delivered to California loads. Much of the data used by the CPUC in developing its generation development scenarios, which the ISO further refined for use in the transmission plan, was initially developed through RETI.

CPUC Long Term Procurement Plan (LTPP)

A memorandum of understanding (MOU) was signed by the CPUC and ISO in May 2010 to formalize coordination between the ISO's RTPP and the CPUC's transmission siting, permitting and the long-term transmission planning processes. The MOU contemplated that the ISO will consider and incorporate the generation scenarios from the LTPP process into its planning process. The CPUC, in turn, will give substantial weight in its siting assessment to project applications that are consistent with the ISO transmission plan. In the later part of 2010, the CPUC released potential renewable procurement portfolios in the LTPP proceeding representing plausible scenarios for meeting 33% RPS goals.

Because of the timing of the development of the CPUC cases, the four resource portfolios documented in this transmission plan are not identical to the CPUC portfolios released in the LTPP. However, the ISO was able to utilize the preliminary CPUC information to develop its portfolios.[3] As was done during the 2010/2011 planning process, the CPUC portfolios will be relied upon as key input into the 2011/2012 planning cycle.

California Transmission Planning Group (CTPG)

The CTPG was formed in the fall of 2009 to conduct joint transmission planning by transmission owners (investor owned utilities and publicly owned utilities) and the ISO. During the 2010/2011 planning cycle the California ISO worked closely with the CTPG to develop a statewide approach to the transmission needed to meet the 33% RPS targets by 2020. During their individual 2010 planning cycles, CTPG members completed a significant amount of technical analyses to develop a framework for preparing a statewide transmission plan. CTPG evaluated alternative renewable resource portfolios based on participant interest, which reflected input from RETI, other stakeholders, and state agencies. Their intent was to develop a conceptual least regrets transmission plan that CTPG members who are the planning entities for their balancing authority areas would assess in greater detail as part of their own respective planning processes. The CTPG statewide transmission plan was completed in early January 2011 and presented a list of high potential and medium potential transmission elements that were identified for further consideration by all CTPG members in their development of their own 2020 RPS planning goals. The ISO performed its own independent analysis and found that the high potential transmission elements identified by CTPG were found to be needed in the ISO's 33% RPS transmission plan.

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[3] As part of its analysis in this cycle, the ISO compared the portfolios actually studied to the CPUC portfolios and found that they were reasonably similar to ISO scenarios, as the data used to construct both sets of scenarios is almost identical and the scenarios share many common elements.

4) 33% RPS Generation Portfolios and Transmission Assessment

The transition to greater reliance on renewable generation creates significant transmission challenges because renewable resource areas tend to be located in places distant from population centers. As a result, development in these areas often requires new transmission lines. The ISO is keenly aware that without transmission in place, developers are extremely reluctant to invest in generation. At the same time, an entirely reactive transmission planning process creates its own problems — most significantly, the time required to develop generation is typically much shorter than the time required to develop a new transmission line. In other words, a transmission process that relies on generators making investments first can leave generation without the necessary transmission for a significant period of time.

The RTPP addresses this challenge and uncertainty by creating a structure for considering a range of plausible generation development scenarios and identifying transmission elements needed to meet the state's 2020 RPS goals. Commonly known as a least regrets methodology, the portfolio approach allows the ISO to consider resource areas (both in-state and out-of-state) where generation build-out is most likely to occur; evaluate the need for transmission to deliver energy to the grid from these areas; and identify any additional transmission upgrades that are needed under one or more portfolios. The ISO 33% RPS assessment is described in detail in chapters 4 and 5 of this plan.

The scenario development methodology is straightforward and begins with evaluating the probability of renewable resource build-out using criteria set forth in the tariff[4]:

Commercial interest in geographic locations evidence by signed purchase power and interconnection agreements;

The results of the CPUC procurement proceedings, as well as similar proceedings sponsored by other regulatory agencies;

Planning level cost estimates of transmission required for alternative resource locations;

Potential energy and capacity values of resources located in various zones;

Publicly available environmental information about the resource locations as well as potential environmental, economic and reliability impacts of additional transmission elements needed to access such resources;

Potential future connections to alternative resource locations;

Potential resource integration requirements;

[4] Section 24.4.6.6

The effect of other transmission upgrades and additions being considered for approval during the planning process; and

The effects of uncertainty on any of the other criteria that could increase the risk of stranded investment.

By weighing the LTPP discounted core[5] procurement information, as well as previously identified transmission projects in various stages of approval, permitting and construction against the tariff criteria, the ISO developed four resource portfolios and populated each one with sufficient generation to meet the 33% RPS goals. Additional transmission was then added to each portfolio as needed to deliver the generation to the ISO grid.

The ISO portfolios cover a broad range of plausible generation possibilities including relatively high levels of internal resources, out-of-state generation and distributed smaller generation, as well as a hybrid portfolio that reflects a balance of potential sources of traditional and renewable energy. The generation resources comprising these four portfolios reflect the latest and best available information on the commercial interests of transmission customers, as measured by interconnection queue positions and whether the resources have signed power purchase agreements with California load-serving entities. Other factors such as cost, procurement policies, permitting, environmental assessments conducted by RETI, and resource financing capabilities were part of the metrics used to evaluate each portfolio. The hybrid portfolio represents an amount of out-of-state renewable procurement that tends to maximize the use of existing import transmission; an amount of distributed generation that exceeds the amount in the CPUC's discounted core, but is plausible, especially given emerging state policies; and a moderate build-out of large in-state renewable generation areas that are already farthest along in development. Given these attributes, the hybrid portfolio was designated as our base case because it is considered the more likely scenario to occur.

According to the tariff and the least regrets methodology, the additional transmission elements added to each portfolio to support the 33% RPS goals were considered to be policy-driven and were placed into category 1 or category 2.

In addition to transmission already approved by the ISO through the transmission planning process, the ISO considered Large Generator Interconnection Procedures (LGIP) network upgrades required to serve renewable resources that either have or were expected to have signed generator interconnection agreements. As such, these transmission upgrades and additions form a core part of the ISO analysis methodology.

The ISO assessment of the transmission projects identified above indicate that those projects with some additional minor system upgrades are sufficient to meet the 33% RPS target by 2020. These transmission

[5] The CPUC chose projects for the discounted core based on two publicly available criteria that adequately demonstrate developer interest: projects must have a signed power purchase agreement (PPA), and a permitting application submitted to the responsible permitting entity (CEC, BLM) must be judged data adequate.

upgrades were tested under the four ISO generation portfolios and all of the projects identified above were determined to be needed.

For this transmission plan, the ISO has concluded that some upgrades to WECC Path 42 are also needed to deliver renewable resources under development in Imperial County that are modeled in the base case portfolio.

The ISO also identified other upgrades that are potentially needed but require further analysis in the next transmission planning cycle as more information becomes available regarding renewable generation development and integration requirements. For example, environmental concerns are growing over the level of development occurring in the California desert. Some of the facilities below would allow development to increase in areas where already disturbed land is available for possible renewable resource development.

Table E1 provides a summary of the various transmission elements of the 2010/11 transmission plan for supporting California's RPS goals. These elements are composed of the following categories:

- Major transmission projects that have been previously approved by the ISO and are fully permitted by the CPUC for construction;
- Additional transmission projects that the ISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the approval process;
- One policy-related transmission project; and
- Policy-related projects that are potentially needed but will be carried forward for evaluation in the next transmission planning cycle.

Table E1: Elements of the 2010/11 ISO Transmission Plan Supporting Renewable Energy Goals

Transmission Facility	Potential Renewable energy Delivery	Renewable Deliverability potential with upgrade
	(TWh)	(MW)
Transmission Facilities Approved and Permitted For Construction		
Sunrise Powerlink	4.1	1,700
Tehachapi Transmission Project	18.2	5,500
Colorado River - Valley 500 kV line	2.9	1,600
Eldorado – Ivanpah 230 kV line	3.6	1,400

Additional LGIP Network Transmission not Permitted		
Borden Gregg Reconductoring	2	800
South of Contra Costa Reconductoring	0.8	300
Pisgah - Lugo	4.1	1,750
West of Devers Reconductoring	5.7	3,100
Carrizo Midway Reconductoring	2.1	900
Coolwater - Lugo 230 kV line	1.4	600
Needed Policy-Driven Transmission Elements		
Mirage-Devers 230 kV reconductoring (Path 42)	3.6	1,400
Potentially Needed Policy-Driven Transmission Elements		
Midway-Gregg 500 kV line		
Gregg - Herndon 230 kV line Reconductoring		
Warnerville - Wilson 230 kV line Reconductoring		
Barton - Herndon 115 kV line Reconductoring		
Manchester - Herndon 115 kV line Reconductoring		
Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)		
400 MVAr reactive power support at Sycamore, Mission, and Talega 230 kV substations		
The third Miguel 500 kV transformer		
Total	48.5	19,050

5) Reliability Assessment

The reliability studies necessary to ensure compliance with North American Electric Reliability Corporation (NERC) and ISO planning standards are a foundational element of the transmission plan. During the 2010/2011 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure compliance with applicable NERC reliability standards. The analysis was performed across a 10-year planning horizon and modeled summer on-peak and off-peak system conditions. The ISO assessed transmission facilities across a voltage bandwidth of 60 kV to 500 kV, and where reliability concerns were identified, the ISO identified mitigation plans to address these concerns. These mitigation plans include upgrades to the transmission infrastructure, implementation of new operating procedures and installation of automatic special protection schemes. All ISO analysis, results and mitigation plans are documented in the transmission plan.

It is the ISO responsibility to conduct its transmission planning process in a manner that ensures planning is appropriately coordinated across its controlled grid as well as its connections with neighboring systems. The analysis that is required to prepare this transmission plan is complex and entails processing a significant amount of data and information. In total, this plan proposes approval of 32 reliability driven transmission projects, representing an investment of approximately $1.2 billion in infrastructure additions to the ISO controlled grid. The majority of these projects (28) cost less than $50 million and has a combined cost of $573 million. The remaining four projects with costs greater than $50 million have a combined cost of $629 million. These reliability projects are necessary to ensure compliance with the NERC and ISO planning standards. A summary of the number of projects and associated total costs in each of the four major transmission owners' service territories is listed below in table E2. Because PG&E and SDG&E have lower voltage transmission facilities (i.e., 138 kV and below) under ISO operational control, a number of projects were identified mitigating reliability concerns in those utilities' areas, compared to none for SCE.

In arriving at these projects, the ISO and transmission owners performed power system studies to measure system performance against the NERC reliability standards and ISO planning standards as well as to identify reliability concerns that included among other things, facility overloads and voltage excursions. Mitigation measures were then evaluated and cost-effective solutions were recommended by ISO staff to management and the Board of Governors for approval.

Table E2 – Summary of Approved Reliability Driven Transmission Projects in the ISO 2010/2011 Transmission Plan

Service Territory	Number of Projects	Cost
Pacific Gas & Electric (PG&E)	23	$683M
Southern California Edison Co. (SCE)	0	$0M
San Diego Gas & Electric Co. (SDG&E)	9	$515M
Total	32	$1,198M

The majority of identified reliability concerns are related to facility overloads or low voltage. Therefore, many of the specific projects that comprise the totals in the table above include line reconductoring and facility upgrades for relieving overloading concerns, as well as installing voltage support devices for mitigating voltage concerns. Additionally, some projects involve building new load-serving substations to relieve identified loading concerns on existing transmission facilities. Several initially identified reliability concerns were mitigated with non-transmission solutions. These include generation redispatch and, for low probability contingencies, possible load curtailment.

6) Economic Studies

Economic studies of transmission needs are another fundamental element of the ISO transmission plan. The objective of these studies is to identify transmission congestion and analyze if the congestion can be cost effectively mitigated by network upgrades. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load. Resolving congestion bottlenecks is cost effective when ratepayer savings are greater than the cost of the project. In such cases, the transmission upgrade can be justified as an economic project.

The ISO economic planning study was performed after evaluating all policy-driven transmission (i.e., meeting RPS targets) and reliability-driven transmission. Network upgrades determined by reliability and renewable studies were modeled as an input in the economic planning database to ensure that the economic driven transmission needs are not redundant and are beyond the reliability- and policy-driven transmission needs. The engineering analysis behind the economic planning study was performed using a production simulation and traditional power flow software.

Grid congestion was identified using production simulation and congestion mitigation plans were evaluated through a cost-benefit analysis. Economic studies were performed in two steps: 1) congestion identification; and 2) congestion mitigation. In the congestion identification phase, grid congestion was simulated for 2015 (the 5th planning year) and 2020 (the 10th planning year). Congestion issues were identified and ranked by severity in terms of congestion hours and congestion costs. Based on these results, the worst congestion issues were identified and ultimately selected as high-priority studies. Compared to the 2009/2010 planning analysis, the 2010/2011 planning results indicated that congestion levels identified in the worst areas were less severe. The change is attributed to a lower load forecast and lower net-short renewable energy requirements used in this year's study.

In the congestion mitigation phase, congestion mitigation plans were analyzed for the worst congestion issues. A total of nine congestion mitigation proposals were evaluated. Stakeholders submitted 41 economic and renewable delivery project proposals through the ISO 2008/09 request window. Seven of the stakeholder proposals aligned with the worst congestion areas and were analyzed in detail. In addition, the ISO identified three other potential congestion mitigation options that were analyzed in detail.

Based on the costs-benefits analyses performed by the ISO for all of the proposed congestion mitigation proposals, the ISO determined that none of the proposed projects demonstrated a positive net benefit. Therefore, the ISO is not recommending any economic upgrades as part of the 2010/2011 planning cycle.

7) Evaluation of the 2008/09 Request Window

As part of the 2010 RTPP planning cycle, the ISO reviewed 41 projects submitted in the 2008 and 2009 request windows. Those projects comprise all request window submissions other than reliability project submissions that the ISO carried forward into the 2010 planning cycle.

The RTPP tariff modifications contemplated that the ISO would evaluate these 2008 and 2009 request window transmission project proposals to determine if they are needed as either policy driven or economically driven transmission projects. These analytic efforts were integrated into the overall transmission planning studies, and relied on the study assumptions, generator portfolio development, methodology, and analysis used in the overall 2010/2011 planning process.

A key consideration in developing these portfolios was to incorporate commercial interest in resources in geographic areas across the ISO grid as well as information from the CPUC and local regulatory authorities' resource planning processes. The renewable portfolio development work performed in CPUC resource planning process included a cost comparison of these resources and as such, the base portfolio information from that work was incorporated in the ISO portfolios. The environmental evaluation data from that process for the zones that the transmission would be interconnecting was also extensively incorporated in the ISO portfolio development process.

The request window projects, excluding seven that were submitted as information only, were evaluated in five areas to determine if they would provide net economic benefits to ratepayers. Those categories are:

Reduction in production cost or other congestion benefits;

Capacity or other electric supply cost benefits;

Transmission system loss reduction benefits;

Emission reduction benefits; and

Policy need.

The results of this analysis found that one of the submissions — the reconductoring of the Devers-Mirage 230 kV double circuit transmission line — is needed as a policy-driven transmission element. This upgrade is part of an overall transmission plan that is coordinated with upgrades planned by Imperial Irrigation District to WECC Path 42.

8) Conclusions and Recommendations

The 2010/2011 ISO transmission plan presents comprehensive results from the first cycle of the ISO's RTPP. This ISO transmission plan, which will be updated annually, provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately meet California's policy goals, in addition to examining conventional grid reliability requirements as well as projects that can bring economic benefits to consumers. This year's plan identified 32 transmission projects, estimated to cost a total of approximately $1.2 billion, as needed to maintain the reliability of the ISO transmission system. While this plan shows that the transmission approved to date can accommodate a diverse range of plausible renewable development scenarios, the ISO will continue to work with state agencies and all stakeholders to evaluate development trends and policy directives beginning with next year's planning cycle and will reassess the transmission needs accordingly.

Chapter 1 Overview of the Revised Transmission Planning Process and the 2010/2011 Transmission Planning Cycle

1.1 INTRODUCTION

The ISO instituted enhancements to its Order 890 transmission planning process that were proposed to FERC in June, 2010 and became effective on December 20, 2010. As the first comprehensive transmission plan presented to the Board of Governors under this revised process, the 2010/2011 comprehensive transmission plan outlines upgrades and additions needed for reliable service, as well as transmission required to meet the state's 33% Renewables Portfolio Standard (RPS) goal. Additionally, to ensure that the transmission plan provides economic efficiency, the ISO conducted production simulation and congestion studies to determine whether ratepayers would benefit from the addition of economically-driven transmission elements. Where appropriate, the ISO also considered non-transmission alternatives and took into account demand response programs that meet required ISO criteria.

The plan is organized into the following chapters:

Chapter 1 – Overview of the Revised Transmission Planning Process and the 2010 – 2011 Transmission Planning Cycle

Chapter 2 – Reliability Assessment – Study Assessment, Methodology and Results

Chapter 3 – Study Results for Other Transmission Studies

Chapter 4 – Study Methodology for Identifying Transmission Needed to Meet the 33% Renewables Portfolio Standard

Chapter 5 – Planning Assessment for 33% RPS Transmission

Chapter 6 – Economic Planning Studies

Chapter 7 – Evaluations of the 2008/09 Request Window Project Submittals

Chapter 8 – Updated Project Schedules and Listing Summary of 2010 Request Window Submittals

Because the modifications to the ISO transmission planning process became effective after the 2010/2011 cycle was well under way, the 2010/2011 transmission planning cycle was initiated under the previous process but will conclude in 2011 under the revised transmission planning process (RTPP). Chapter 1 provides an overview of the revised planning process, the 2010/2011 planning and stakeholder process, and next steps for the 2011/2012 planning cycle.

1.2 THE REVISED TRANSMISSION PLANNING PROCESS

1.2.1. Need for transmission planning process enhancements

On June 4, 2010, following a ten-month stakeholder process, the ISO submitted to FERC a comprehensive proposal to revise its transmission planning process. This proposal, known as RTPP, was motivated by the recognition that most transmission additions and upgrades over the next decade will be driven by the need to access renewable electricity supply resources in response to California's 33% RPS. The existing transmission planning processes and rules simply were not well suited to the new world in which infrastructure needs are driven by environmental policies that trigger major changes in the supply fleet over a ten-year period – a relatively short time for normal transmission planning and development.

A crucial challenge for transmission planning in the new environmental policy-driven context is to develop sufficient transmission on a timetable that supports the 33% RPS goals and to develop such transmission efficiently – and in the right places – so ratepayers are not saddled with high costs of under-utilized transmission. Contributing to this challenge is the great uncertainty about which of the identified areas rich in renewable energy potential will realize the most generation development. The revised planning process: 1) identifies and approves transmission projects that have the highest likelihood of being fully utilized; 2) identifies, for later reevaluation, projects that could be highly utilized but whose approval must await stronger evidence of committed generation development; 3) addresses the more conventional requirements of transmission planning such as reliability needs and congestion reduction; and 4) organizes all these elements into an annual comprehensive plan that accommodates 33% renewable energy portfolios by 2020.

A second major factor affecting the RTPP design was the need for a new public policy-driven category of transmission additions and upgrades. The prior ISO planning rules provided for reliability and economic projects, as well as more narrowly defined transmission categories, to be submitted for evaluation through a request window. In order to be eligible for cost recovery through the ISO transmission access charge (TAC) a project had to meet the criteria for one of these project categories. For example, a reliability project must be shown to be the preferred cost effective solution to a reliability problem identified through annual reliability studies. An economic project must be shown to offer economic benefits, such as reducing system production costs through mitigation of chronic congestion identified in the annual congestion studies, with savings that exceed the project's costs. In contrast, transmission elements needed to meet the 33% RPS goals typically would not qualify for either of these categories because they are explicitly identified to meet needs that are neither reliability- nor economic-based. Thus, in order to enable the transmission planning process to identify such projects and approve them for cost recovery through the TAC, the ISO had to amend its tariff to include the public policy-driven category.

The third major factor driving the RTPP enhancements was the infeasibility of the request window structure for economic projects. As it was structured prior to the RTPP modifications, the request window allowed any party to submit a project proposal irrespective of any previously identified need and required the ISO to allocate substantial staff resources to evaluate such submissions even when there was little likelihood that the project would be needed. Under the prior request window process for economic projects, the project proponent retained the right to build the project if the ISO determined that the project or something very similar was needed under the existing criteria, thus encouraging parties to submit as many project proposals as possible in order to establish rights to build TAC-based transmission. With the state's adoption of the RPS goals and the resulting potential need for substantial new transmission over the next ten years, the inefficiency of the request window would have increased because of the greater incentive for parties to submit more project proposals to establish rights to build and the complexity involved in evaluating these proposals.

Fourth, although the request window structure was problematic, a need existed to involve independent transmission developers in the planning process and provide them explicit, well-defined opportunities to build needed transmission under the TAC-based cost recovery paradigm (in addition to the merchant transmission paradigm). In practical terms, certain types of transmission additions and upgrades are most appropriately and efficiently built by incumbent Participating Transmission Owners (PTOs), most notably to address reliability problems on their own systems or when upgrading an existing facility is the most economical solution. In other instances, however, it is important to allow competition among interested and capable developers. The new transmission planning process provides for such competition by conducting an open request for proposals to build and own, under TAC cost recovery, transmission elements in the economic and policy-driven categories that are found to be needed in the comprehensive transmission plan.

The fifth major driver of the RTPP design was the need to better coordinate transmission planning with generator interconnection procedures (GIP), so that the planning and approval of new transmission for the ISO grid could be more holistic and comprehensive. Under the GIP, the ISO and the PTOs are required to provide the network upgrades needed for interconnection customers for which certain GIP milestones are completed (i.e., the phase 2 interconnection studies and the posting of required security by the customer). But prior to the RTPP, however, there were no provisions for ISO planners to evaluate the identified network upgrades within the broader context of transmission planning to identify more efficient upgrades and additions that could meet other planning objectives as well as the needs of the interconnection customers. For example, there were no provisions for enhancing or expanding these GIP-driven upgrades to anticipate the interconnection of additional generation that is in the interconnection queue to be studied in later clusters. At the same time, in the 33% renewable policy context, it is important that the transmission planning process anticipate the needs of the generators in these later queue positions in order to identify cost-efficiency opportunities.

Moreover, due to the expected concentration of renewable generation in a number of promising geographic areas, it is likely that the most efficient way to develop transmission to meet the 33% goal will be to expand or enhance network upgrades identified in the GIP. In other words, the most efficient strategy for developing transmission under the new public policy-driven category will likely be to use this category as a basis for approving enhancements to GIP-driven network upgrades. But this meant that the two processes – the GIP and transmission planning – had to be coordinated more explicitly than in the past.

1.2.2 Similarities and differences between the prior transmission planning process and RTPP

The ISO RTPP retains some elements of the former transmission planning process. Under the RTPP, the ISO will still hold a stakeholder process at the beginning of each planning cycle (in the first quarter of each calendar year) to establish unified planning assumptions and a study plan. The ISO will perform its reliability studies, publish the results and propose solutions to identified reliability problems, require PTOs to propose solutions to problems identified on their systems, and accept additional solution proposals from other parties before conducting a stakeholder process to discuss all the elements. The ISO will conduct congestion studies and identify areas of the grid where congestion is substantial and where an economic transmission project may be justified on a cost-benefit basis. The ISO will identify any issues with the feasibility of long-term congestion revenue rights and will propose solutions. The ISO will continue to accept, evaluate, and act on proposals for locational constrained resource interconnection (LCRI) projects and merchant projects.

The ISO will discuss all the elements of the planning cycle with stakeholders through an open process. The comprehensive transmission plan will be presented to the ISO Board in the fifteenth month of the planning cycle.

The substantial differences between the prior process and RTPP include the following:

- The new planning cycle has three phases.[6] Phase three begins after the ISO Board approves the comprehensive transmission plan and encompasses the competitive solicitation process for policy-driven category 1 and economically-driven elements found to be needed in the plan.
- The request window is limited to reliability projects, merchant projects, LCRI projects and projects proposed to maintain the feasibility of long-term CRRs.
- Request window project submissions, other than merchant projects, will not confer a right to build on the sponsor of the submission. Rather, once the ISO determines which projects should be approved, the rights or obligations to build and own projects will be determined through the applicable tariff rules for each project category.
- During phases one and two, the ISO will develop a conceptual statewide plan, including information from neighboring balancing authorities and planning entities, and solicit stakeholder comment. This plan and stakeholder comments will be inputs into the comprehensive plan that the ISO develops for its footprint.
- The comprehensive plan will identify policy-driven and economically-driven elements that, upon approval by the Board, will be the basis for the competitive solicitation in phase three in which both non-incumbent transmission developers and PTOs may participate.
- Starting with the 2011/2012 cycle, the ISO will evaluate certain network upgrades identified in GIP as part of the transmission planning process.
- During the 2010/2011 cycle, the ISO evaluated economic projects submitted in the 2008 and 2009 request windows. If any of those projects lined up with policy-driven or economically-driven needed elements, the project proponent would have the right to finance, own and construct such project.

1.2.3 Blending the Old and the New

[6] Under RTPP terminology, the new process is divided into "phases" rather than the "stages" used in the prior planning process. However, the purpose of the "phases" is similar to the "stages" in that each phase provides a demarcation of the process milestones and triggers certain stakeholder activities.

The ISO's proposed modifications to the transmission planning process were suspended by FERC on July 26, 2010 and became effective on December 20, 2010. In anticipation that the 2010/2011 cycle would be governed by two different tariff processes, the ISO took several steps to align its planning activities with the milestones under each process by:

- Seeking (and receiving) a waiver from FERC from the prior requirement that economic projects be submitted into the 2010 request window;
- Amending the request window dates in its Business Practice Manual (BPM) for transmission planning to allow time for FERC to act on the waiver request.
- Utilizing the flexibility under the prior tariff to conduct a comprehensive analysis of system needs using resource scenarios that accomplish the 33% by 2020 renewable generation policy objective;
- Posting base cases and holding an additional stakeholder meeting in early December to discuss the preliminary results of its 33% renewable and economic studies; and
- Issuing a conceptual statewide plan and soliciting stakeholder comment prior to posting this plan.

The 2010/2011 process details are discussed in section 1.3.

1.2.4 Collaborative Planning Efforts

The ISO, utilities, state agencies and other stakeholders are working closely to assess how to meet the environmental goals established by state policy. Their collaboration is visible in several recent initiatives:

- **Renewable Energy Transmission Initiative (RETI):** This is a joint initiative between the ISO, California Public Utilities Commission (CPUC), California Energy Commission (CEC), investor-owned and publicly-owned utilities and other stakeholders. RETI identified areas in California and neighboring states with concentrations of high-quality renewable resources that could be delivered to California loads. Much of the data used by the CPUC in developing its discounted core projects and its defined generation development scenarios as well as the ISO generation development scenarios were initially developed through RETI. The RETI effort was also a major input into the California Transmission Planning Group (CTPG) effort.

- **Reformed Long-Term Procurement Planning:** In 2008, the CPUC began a process of reforming its Long Term Procurement Plan process to better support the need to meet state policy goals. This effort resulted in standards that the IOUs need to meet in their 2010 plans. Those standards include a set of the following four renewable resource scenarios: cost-constrained, time-constrained, environmentally-constrained, and trajectory. While these cases are not identical to the four resource scenarios developed by the ISO, the data used to construct both sets of scenarios is almost identical and the scenarios share many common elements.

- **California Transmission Planning Group (CTPG):** This group was formed in the fall of 2009 to conduct joint transmission planning by transmission owners (investor and publicly owned utilities) and the ISO. These parties have the technical capability to perform detailed transmission planning and the statutory obligation to provide reliable transmission service to serve California consumers within their service territories. The 2010 statewide plan produced by the CTPG is intended to be conceptual rather than a prescriptive plan for meeting the state's 33% RPS goals. The ISO considered the study methodologies and findings from the CTPG effort and incorporated them into its studies. However, one major difference between the ISO and CTPG study methodologies was the ISO use of a security-constrained production simulation model to establish major transmission path flows and conventional generation dispatch assumptions. This difference resulted in greater utilization of existing and proposed transmission. As a result, the scope of the ISO transmission plan for achieving the 33% RPS goals is smaller than what CTPG has projected.

- **CPUC-ISO Memorandum of Understanding.** The CPUC and ISO signed a Memorandum of Understanding in May 2010 that formalized coordination between the ISO revised transmission planning process and CPUC's transmission siting, permitting and long-term procurement planning processes. Specifically, the ISO will consider and incorporate the generation scenarios from the procurement process into its planning process to identify transmission needed to access the renewable energy produced by those generators. The CPUC, in turn, will give substantial weight in its siting assessments to projects approved in the ISO comprehensive transmission plan. However, the ISO had to stay on schedule for completing its comprehensive transmission plan by the end of 2010 while the CPUC portfolio development process was not completed until almost the end of 2010. Therefore, the ISO had to use preliminary CPUC information and anticipate what the CPUC portfolios would ultimately be. Once the CPUC completed their portfolios in late 2010, the ISO compared portfolios it studied to the CPUC portfolios and found that they were generally similar. Further description of the ISO's scenario development can be found in chapter 4.

1.3. The 2010/2011 Transmission Planning Cycle

1.3.1 Process and Stakeholder Schedule

The 2010/2011 annual planning cycle began in December, 2009 when the ISO staff reached out to neighboring balancing authorities and other regional planning entities seeking information that could be incorporated into the unified planning assumptions and study plan. The draft study plan was posted for stakeholder review on February 5, 2010 and a meeting was held on February 12, 2010. Following the meeting and an opportunity for comments, the final draft planning assumptions and study plan were posted on March 31, 2010.[7]

The ISO completed the technical study base cases and posted them on its secured website on April 19, 2010. Stakeholders were given an opportunity to provide input via conference call on April 26, 2010. Following the call, all other planning data was posted on the secured website on May 3, 2010.

[7] The Unified Planning Assumptions and Study Plan can be found at http://www.caiso.com/276a/276af0692d6e0.pdf.

On September 10, 2010, the ISO posted the technical study results for long-term CRR feasibility and the system reliability assessments. This posting triggered the 30 day period within which PTOs must submit reliability projects through the request window responding to the reliability concerns identified in the studies. As noted briefly above, for the 2010-2011 cycle, the ISO revised the dates for the request window through the BPM change management process so that the window would open on the date that the PTOs submitted reliability projects and close 60 days later. Because the technical studies were posted on September 10, the request window opened on October 10 and closed on December 10, 2010.

A stakeholder meeting was held on October 26 and 27, 2010 to discuss the ISO technical study results and the PTO reliability projects. The ISO also arranged two other stakeholder engagements prior to posting this draft comprehensive plan on March 24, 2011. On December 2, 2010, the ISO held a stakeholder meeting to address preliminary results of the 33% RPS portfolio evaluation and the preliminary results of the congestion studies. A follow-up conference call was held on December 16, 2010 to provide an opportunity for additional questions and discussion.

In order to complete the process steps required by RTPP, the ISO issued a conceptual statewide plan on January 17, 2011 and solicited stakeholder comments that were submitted on February 23, 2011. The ISO also advised stakeholders, in a market notice issued on February 18, 2011, that in order to allow sufficient time to evaluate stakeholder input and develop this comprehensive plan, the plan would be presented to the Board for approval at the May 2011 meeting. Stakeholders were also advised that the draft plan would be posted on March 24, 2011 and that a final stakeholder meeting was scheduled for March 30, 2011.

1.3.2 Unified Planning Assumptions and Study Plan

For the 2010/2011 cycle, the study plan contained a description of the study assumptions for the ISO reliability assessments, the long-term CRR feasibility study, the short term operational studies, a description of the locational capacity studies and a brief reference to economic planning study requests. In addition, the study plan described the once through cooling (OTC) study being conducted in conjunction with the CPUC and the CEC.

In the study plan, the ISO described the development of the base case assumptions for its reliability assessments. Specifically, the ISO explained that in light of the state's 33% RPS by 2020, a 33% RPS scenario for renewable resources should be modeled in the planning base cases in this planning cycle. The ISO proposed to rely on information from its generation interconnection process to determine the amount and location of renewable resources in the reliability base cases. Specifically, for the GIP serial study group the ISO used renewable generation and associated transmission that had been identified in interconnection agreements. For renewable generation in the transition cluster, the ISO included generation projects and associated transmission upgrades in the phase two cluster studies.[8]

[8] Study Plan at pages 11-12.

The study plan also identified all of the other assumptions for the reliability studies and the other technical studies to be conducted during phase 2 of the planning cycle. As noted above, technical study results, with the exception of economic and congestion study results, were posted on September 10, 2010.

1.3.3 Comprehensive Transmission Planning

Once the reliability studies and other technical assessments were completed, the ISO moved forward with developing the 33% RPS portfolio scenario that would be used for a comprehensive look at the needs of the system over a ten year planning horizon. The reliability assessment results and reliability projects determined to be needed during this cycle, as well as other request window projects proposed for approval, formed the basis for this comprehensive system study. GIP network upgrades were also included as baseline assumptions in the comprehensive study.[9] The 33% RPS scenario base cases were posted to the ISO's secure website on September 15, 2010, and later with updated 33% RPS portfolio cases on November 29, 2010.

1.3.4 Analysis of the 2008/2009 Economic Request Window Submissions

During the 2008 and 2009 planning cycles, participants in the ISO transmission planning process submitted economically-driven projects through the request window. The ISO concluded that an appropriate analysis of these projects must be based on a comprehensive view of system needs in light of the 33% RPS and included a specific tariff provision addressing the evaluation of these submissions as part of the revised transmission planning process enhancements.

Although the revised tariff language was not yet in effect, the ISO nonetheless advised FERC and its stakeholders that these projects would be evaluated in the 2010/2011 cycle. Accordingly, the ISO conducted an economic analysis of the 2008 and 2009 request window submissions based on the comprehensive plan study scenarios. The results of the economic analyses for the 2008 and 2009 request window submissions are described in chapter 7.

1.4 2010-2011 Transmission Planning Process External Inputs

1.4.1 Sub-Regional Planning Coordination

Regional and sub-regional coordination is one of the Order No. 890 principles and is required by both the tariff and BPM. In addition to soliciting information for the unified planning assumptions when the cycle is initiated each year, the ISO is a member of Western Electricity Coordinating Council (WECC) and its **Transmission Expansion Planning Policy Committee** (TEPPC) and actively participates in the development of the database used throughout the western interconnection.

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[9] In the 2010/2011 planning cycle the ISO did not evaluate GIP-driven network upgrades for potential efficiency-improving enhancement. In accordance with the FERC-approved RTPP the ISO will begin to perform this type of evaluation in the 2011/2012 cycle.

During this cycle, the ISO also worked closely with the CTPG to develop a statewide approach to the transmission needed to meet the 33% RPS. CTPG includes transmission owners with service territories and transmission operators (i.e., parties that have both the responsibility for transmission planning and the technical capabilities to perform the required activities). CTPG evaluated alternative renewable resource portfolios based on participant interest and reflecting input from RETI, other stakeholders and state agencies. One explicit CTPG objective is to identify opportunities for joint transmission projects, which the ISO believes is an important focus and potential benefit of developing a statewide 33% renewable transmission plan. The ISO used some of the data developed by CTPG in the 33% RPS scenarios studied in the comprehensive planning study.

1.4.2 Coordination with Regulatory Agencies

The CPUC and the CEC participated in the 2010/2011 transmission planning process and provided input that was reflected in the development of the 33% RPS scenarios. Additionally, the ISO used data from the CPUC long-term procurement proceedings and coordinated its scenario development with the scenarios developed by the CPUC staff for use in that proceeding. Further description of the ISO's scenario development can be found in chapter 4.[10]

1.4.3 Coordination with RETI

Analysis developed by RETI was incorporated into the ISO work through the CPUC's development of portfolios, and through the CTPG reliance on RETI analysis in advancing the comprehensive plan as discussed earlier. Also the ISO utilized RETI environmental impact scores, as refined by Aspen Environmental Group, in the development of its four 33% RPS portfolios.

1.5 NEXT STEPS UNDER RTPP 2011/2012 PLANNING CYCLE

Phase 1 of the 2011/2012 planning cycle is currently underway. Under RTPP, during phase 1 and the development of the unified planning assumptions and study plan, stakeholders will be given an opportunity to submit economic planning study requests, demand response programs and generation alternatives for consideration as study assumptions in the study plan. The ISO will also identify and seek stakeholder input on the policy objectives that will form the basis for its comprehensive evaluation of the need for policy-driven projects. It is anticipated that the ISO will propose that the 33% RPS by 2020 policy goal is used in the 2011/2012 cycle. The ISO also expects to include, as a related policy objective for the RTPP, that renewable resources imported from outside the ISO balancing authority, as identified in the appropriate ISO 33% RPS baseline scenario, be fully deliverable for resource adequacy (RA) purposes. This will enable broader competition for the supply of economical renewable resources.

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[10] The ISO also participates in CPUC proceedings and is currently developing modeling techniques that will assist load serving entities in making procurement decisions regarding resources needed to integrate renewable resources into the ISO grid. ISO 33% RPS Integration Study Production Simulation models are posted in the following website (**http://www.caiso.com/23bb/23bbc01d7bd0.html**)

Chapter 2 Reliability Assessment - Study Assumptions, Methodology and Results

2.1 OVERVIEW OF THE ISO RELIABILITY ASSESSMENT

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

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

The focus of the annual reliability assessment is to identify facilities that indicated a potential of not meeting the applicable performance requirements specifically outlined in section 2.2.
The study used WECC full-loop power flow base cases and was performed as part of the ISO's annual transmission planning process that is defined in the BPM for the transmission planning process[11].

2.1.1 Backbone (500 kV and select 230 kV) system area assessment

For the backbone system assessment, conventional and governor power flow studies and stability studies were performed to evaluate the system performance under normal conditions and following the contingencies of power system equipment of voltage levels 230 kV and above. The backbone transmission system studies include:

- Northern California-PG&E system;
- Southern California-SCE system; and
- Southern California-SDG&E system.

2.1.2 Local area assessments

For the local area non-simultaneous assessments, conventional and governor power flow studies were performed under normal system conditions and contingency system conditions of power system equipment of voltage levels 60 kV through 230 kV. These assessments were performed for eight local PG&E service territory areas listed below.

- Humboldt area;
- North Coast and North Bay area;
- North Valley area;
- Central Valley area;
- Greater Bay area;

[11] https://bpm.ISO.com/bpm/bpm/version/000000000000105

- Greater Fresno area;
- Kern area; and
- Central Coast and Los Padres area.

2.2 RELIABILITY STANDARDS COMPLIANCE CRITERIA

This 2010/2011 transmission plan spanned a 10 year planning horizon and was performed to ensure the ISO's balancing authority area is in compliance with the North American Electric Reliability Corporation (NERC), WECC and ISO reliability standards across the 2011 through 2020 planning horizon. Sections 2.2.1 through 2.2.4 describe how these planning standards were applied in the 2010/2011 study.

2.2.1 NERC Reliability Standards

NERC reliability standards[12] set forth criteria for meeting system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the ISO as a registered NERC planning coordinator and were considered in the reliability assessment:

- TPL-001: System Performance Under Normal Conditions (Category A);
- TPL-002: System Performance Following Loss of a Single Bulk Electric System (BES) Element (Category B);
- TPL-003: System Performance Following Loss of Two or More BES Elements (Category C); and
- TPL-004: System Performance Following Extreme BES Events (Category D).

2.2.2 WECC Reliability Standards

The WECC reliability standards[13], like the NERC reliability standards, set forth additional criteria for meeting system performance requirements that must be met under a varied but specific set of operating conditions. These WECC Reliability Standards are applicable to the ISO as a member of the WECC.

2.2.3 Low Voltage Requirements

The low voltage requirements for NERC and WECC Categories B and C contingencies are established by the Participating Transmission Owner (PTO) responsible for each service territory. Table 2.2-1 provides the voltage guidelines that were used in the assessment.

[12] http://www.nerc.com/page.php?cid=2%7C20
[13] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71

Table 2.2-1: Voltage Guidelines Utilized in the Assessment

ISO / PTO	Voltage level kV	Normal Conditions		Contingency Conditions		Category D	WECC Voltage Deviation Criteria	
		Vmin	Vmax	Vmin	Vmax		Category B	Category C
PG&E	115 kV and below	0.90 p.u.	1.1	0.90 p.u.	1.1 but not clear standard	checked for voltage collapse, stability issues, and cascading outages	-	-
PG&E	230 kV and above (500 kV)	N/A – Generally, normal voltage on the 500 kV system is higher 1 PU at the starting point	1.1	N/A – Already captured by voltage deviation criteria	N/A – Already captured by voltage deviation criteria	Checked for voltage collapse, stability issues, and cascading outages	≤5%	≤10%
SCE	bellow 220	0.95	1.05	0.9	1.1			
SCE	220	Bulletin #17	1.05	0.9	1.1	evaluate for risks and consequences	≤7%	≤10%
SCE	500	Bulletin #17	1.07	0.9	1.1	evaluate for risks and consequences	≤7%	≤10%
SDG&E	69-230 kV	SDG&E Operating Procedure TMC1005				evaluate for risks and consequences	≤5%	≤10%
SDG&E	500	SDG&E Operating Procedure TMC1005					≤5%	≤10%

2.2.4 California ISO Grid Planning Standards

The California ISO Grid Planning Standards (ISO standards)[14] specify the planning standards to be used in the planning of ISO transmission facilities. These standards:

- Address specifics not covered in the NERC reliability and WECC planning standards;
- Provide interpretations of the NERC reliability and WECC planning standards specific to the ISO grid; and

[14] http://www.ISO.com/docs/09003a6080/14/37/09003a608014374a.pdf

Chapter 2 Reliability Assessment - Study Assumptions, Methodology and Results

2.1 Overview of the ISO Reliability Assessment

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

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

The focus of the annual reliability assessment is to identify facilities that indicated a potential of not meeting the applicable performance requirements specifically outlined in section 2.2.
The study used WECC full-loop power flow base cases and was performed as part of the ISO's annual transmission planning process that is defined in the BPM for the transmission planning process[11].

2.1.1 Backbone (500 kV and select 230 kV) system area assessment

For the backbone system assessment, conventional and governor power flow studies and stability studies were performed to evaluate the system performance under normal conditions and following the contingencies of power system equipment of voltage levels 230 kV and above. The backbone transmission system studies include:

- Northern California-PG&E system;
- Southern California-SCE system; and
- Southern California-SDG&E system.

2.1.2 Local area assessments

For the local area non-simultaneous assessments, conventional and governor power flow studies were performed under normal system conditions and contingency system conditions of power system equipment of voltage levels 60 kV through 230 kV. These assessments were performed for eight local PG&E service territory areas listed below.

- Humboldt area;
- North Coast and North Bay area;
- North Valley area;
- Central Valley area;
- Greater Bay area;

[11] https://bpm.ISO.com/bpm/bpm/version/000000000000105

- Greater Fresno area;
- Kern area; and
- Central Coast and Los Padres area.

2.2 Reliability Standards Compliance Criteria

This 2010/2011 transmission plan spanned a 10 year planning horizon and was performed to ensure the ISO's balancing authority area is in compliance with the North American Electric Reliability Corporation (NERC), WECC and ISO reliability standards across the 2011 through 2020 planning horizon. Sections 2.2.1 through 2.2.4 describe how these planning standards were applied in the 2010/2011 study.

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- TPL-001: System Performance Under Normal Conditions (Category A);
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- TPL-004: System Performance Following Extreme BES Events (Category D).

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The low voltage requirements for NERC and WECC Categories B and C contingencies are established by the Participating Transmission Owner (PTO) responsible for each service territory. Table 2.2-1 provides the voltage guidelines that were used in the assessment.

[12] http://www.nerc.com/page.php?cid=2%7C20
[13] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71

Table 2.2-1: Voltage Guidelines Utilized in the Assessment

<table>
<tr><th rowspan="2">ISO / PTO</th><th rowspan="2">Voltage level kV</th><th colspan="2">Normal Conditions</th><th colspan="2">Contingency Conditions</th><th>Category D</th><th colspan="2">WECC Voltage Deviation Criteria</th></tr>
<tr><th>Vmin</th><th>Vmax</th><th>Vmin</th><th>Vmax</th><th></th><th>Category B</th><th>Category C</th></tr>
<tr><td rowspan="2">PG&E</td><td>115 kV and below</td><td>0.90 p.u.</td><td>1.1</td><td>0.90 p.u.</td><td>1.1 but not clear standard</td><td>checked for voltage collapse, stability issues, and cascading outages</td><td>-</td><td>-</td></tr>
<tr><td>230 kV and above (500 kV)</td><td>N/A – Generally, normal voltage on the 500 kV system is higher 1 PU at the starting point</td><td>1.1</td><td>N/A – Already captured by voltage deviation criteria</td><td>N/A – Already captured by voltage deviation criteria</td><td>Checked for voltage collapse, stability issues, and cascading outages</td><td>≤5%</td><td>≤10%</td></tr>
<tr><td rowspan="3">SCE</td><td>bellow 220</td><td>0.95</td><td>1.05</td><td>0.9</td><td>1.1</td><td></td><td></td><td></td></tr>
<tr><td>220</td><td>Bulletin #17</td><td>1.05</td><td>0.9</td><td>1.1</td><td>evaluate for risks and consequences</td><td>≤7%</td><td>≤10%</td></tr>
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</table>

2.2.4 California ISO Grid Planning Standards

The California ISO Grid Planning Standards (ISO standards)[14] specify the planning standards to be used in the planning of ISO transmission facilities. These standards:

- Address specifics not covered in the NERC reliability and WECC planning standards;
- Provide interpretations of the NERC reliability and WECC planning standards specific to the ISO grid; and

[14] http://www.ISO.com/docs/09003a6080/14/37/09003a608014374a.pdf

- Identify whether specific criteria should be adopted that are more stringent than the NERC/WSCC planning standards.

At this point the ISO standards define a more stringent requirement for all TPL-002 disturbances than is specified by the NERC reliability and WECC planning standards. For the ISO, acceptable system performance for the TPL-002 standard is bound by loss of a single bulk electric system element when one generator is already out-of-service, where NERC and WECC define the TPL-002 standard as system performance following loss of a single bulk electric system element[15].

2.2.5 Nuclear Plant Interface Requirements (NUC-001-2)

The purpose of this standard[16] is to ensure coordination between the nuclear plant generator operators and transmission entities to ensure safe operation of the nuclear plant. The NUC-001-2 standard requires the transmission planners to perform planning studies and analyses in accordance to the Transmission Control Agreements (Appendix E)[17] with the Nuclear Plant Generator Operators. The Transmission Control Agreements provides voltage requirements, as well as stability requirements, for the off-site power supply to the Diablo Canyon and San Onofre nuclear generating station (SONGS) under various generating or transmission contingency conditions.

2.2.6 Observing System Operating Limits Standard Requirements (FAC-014-2)

The purpose of this standard is to ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the bulk electric system are determined based on an established methodology. SOLs used in planning studies follow and comply with the NERC and WECC reliability standards.

[15] Section II of http://www.ISO.com/docs/09003a6080/14/37/09003a608014374a.pdf
[16] http://www.nerc.com/files/NUC-001-2.pdf
[17] http://www.ISO.com/docs/09003a6080/25/a3/09003a608025a385.pdf

2.3 Study Methodology and Assumptions

Sections 2.3.1 and 2.3.2 summarize the study methodology and assumptions used for the reliability assessment.

2.3.1 Study Methodology

As noted earlier, the assessment of the backbone and local areas were performed using conventional analysis tools and widely accepted generation dispatch approaches. These methodology components are briefly described below.

2.3.1.1 Generation Dispatch

All generating units in the area under study were dispatched at or close to their maximum power (MW) generating levels. Qualifying Facilities (QFs) and self-generating units were modeled based on their historical generating output levels.

2.3.1.2 Power Flow Contingency Analysis

Conventional and governor power flow contingency analyses were performed on all backbone and local areas consistent with NERC TPL-001 through TPL-004, WECC, and ISO standards as outlined in section 2.2. Transmission line and transformer bank ratings in the power flow cases were updated to reflect the rating of the most limiting component or element. All power system equipment ratings were consistent with information in the ISO Transmission Register.

Based on historical forced outage rates of combined cycle power plants on the ISO controlled grid, the G-1 contingencies of these generating facilities were classified as an outage of the whole power plant that could include multiple units. Examples of such power generating facilities are the Delta Energy Center (DEC) which is comprised of three combustion turbines and a single steam turbine.

2.3.1.3 Post Transient Analyses

For the ISO balancing authority area backbone system assessment, post transient analyses were performed to ascertain compliance with the WECC post transient voltage deviation standards, with one exception being the SCE system. For the SCE system, consistent with the SCE guidelines for 7% deviation requirements for N-1 contingencies, the 7% and 10% voltage deviation guidelines were applied for the N-1 and N-2 contingency analyses respectively. The WECC standards specify maximum post-transient voltage deviation of 5% and 10% for Categories B and C contingencies, respectively, for impacts caused on other systems. The SCE's post-transient voltage deviation guidelines apply to its own system and not to other systems. For impacts caused on other systems, all PTOs follow WECC standards on post-transient voltage deviations.

2.3.1.4 Transient Stability Analyses

Transient stability simulations were also performed as part of the backbone system assessment ensures system stability and positive damping of system oscillations for critical contingencies. This ensured that the transient stability criteria for performance levels B and C as shown in table 2.3-1 were met.

Table 2.3-1: WECC transient stability criteria

<table>
<tr><th>Performance Level</th><th>Disturbance</th><th>Transient Voltage Dip Criteria</th><th>Minimum Transient Frequency</th></tr>
<tr><td rowspan="4">B</td><td>Generator</td><td rowspan="4">Max voltage dip - 25% Max duration of voltage dip not exceeding 20% - 20 cycles. Not to exceed 30% at non-load buses.</td><td rowspan="4">59.6 Hz for 6 cycles or more at a load bus.</td></tr>
<tr><td>One Circuit</td></tr>
<tr><td>One Transformer</td></tr>
<tr><td>PDCI</td></tr>
<tr><td rowspan="3">C</td><td>Two Generators</td><td rowspan="3">Max voltage dip - 30% at any bus. Max duration of voltage dip exceeding 20% - 40 cycles at load buses.</td><td rowspan="3">59.0 Hz for 6 cycles or more at a load bus.</td></tr>
<tr><td>Two Circuits</td></tr>
<tr><td>IPP DC</td></tr>
</table>

2.3.2 Study Assumptions

The following study horizon and assumptions were modeled in the 2010/2011 ISO transmission planning analysis.

2.3.2.1 Study Horizon

The NERC standards, TPL-001 through TPL-003 (given in section 2.2.1) and compliance related studies were performed for both the near-term (i.e., year 2015) and long-term (i.e., year 2020) scenarios. Additional studies for the NERC TPL-004 standards which relate to extreme system events were performed for the near-term (2015) scenarios only.

2.3.2.2 Peak Demand

In 2010 the ISO balancing authority area peak demand was 47,350 MW and occurred on August 25, 2010 at 4:20 p.m. The peak demands for PG&E occurred on the same date and time at 21,297 MW. However, SCE and SDG&E peak demands occurred on a different date and times: (a) for SCE, it occurred on September 27, 2010, at 2:51 p.m. with 23,678 MW; and (b) for SDG&E, it also occurred on September 27, 2010, however, at 3:25 p.m. with 4,684 MW.

Most of the ISO balancing authority area experiences summer peaking conditions. Hence, summer peak conditions were mainly considered in all studies. For areas that experienced highest demand in the winter season, or where historical data indicated other conditions may require separate studies, winter peak and summer off-peak studies were also performed. Examples of such areas are Humboldt, Greater Fresno and the Central Coast in the PG&E service territory. Table 2.3-2 summarizes these study areas and the corresponding peak scenarios for the reliability assessment.

Table 2.3-2: Summary of study areas, horizon and peak scenarios for the reliability assessment

Study Area	2011 through 2015	2020
Humboldt	Summer Peak Winter Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak	Summer Peak
North Valley	Summer Peak	Summer Peak
Central Valley	Summer Peak	Summer Peak
Greater Bay Area	Summer Peak	Summer Peak
Fresno	Summer Peak Summer Off-Peak	Summer Peak
Kern	Summer Peak Summer Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak	Summer Peak Winter Peak
Northern Califronia (PG&E) Bulk System*	Summer Peak Summer Off-Peak	Summer Peak
Southern California Edison (SCE) area	Summer Peak	Summer Peak
San Diego Gas and Electric (SDG&E) area	Summer Peak	Summer Peak
Entire Southern California*	Summer Peak Summer Off-Peak	Summer Peak Summer Off-Peak

*The studies in these areas will be conducted on 2015 and 2020 scenarios only

2.3.2.3 Stressed Import Path Flows

As part of the interconnected transmission system in California, the ISO balancing authority area is interconnected with neighboring balancing authority areas through interconnections over which power can be imported or exported to and from the ISO balancing authority area. The power that flows across these import paths are an important consideration in developing the study base cases. For the 2010/2011 planning study and consistent with operating conditions for a stressed system, high import path flows were modeled to serve the ISO's balancing authority area load. These import paths are discussed in more detail *in section 2.3.2.10.*

2.3.2.4 Contingencies

In addition to studying the system under TPL-001 (normal operating conditions), the following provides additional detail on how the TPL-002, TPL-003, and TPL-004 standards were evaluated.

TPL-002

For this standard, loss of a single BES element which included loss of one generator (G-1), one transformer (T-1), one transmission line (L-1), DC lines, and a selected loss of one generator, one transmission line (G-1/L-1), all outages of transmission facilities in the ISO balancing authority area of voltage levels 115 kV and above, and most of the 60 kV, 69 kV and 70 kV facilities were studied. The outages of transmission facilities that comprise the import paths with neighboring balancing authority areas were also studied. The list of contingencies was provided on the ISO secured website.

TPL-003

For this standard, loss of two or more BES elements which included loss of two transmission facilities in the same corridor, DCTL outages, loss of two nuclear units and a large number of two element outages (i.e., C-3 contingencies) were studied. In general, because many of the transmission facilities evaluated under the TPL-003 standard are major paths designed to transfer large amounts of power, the results of the analysis was considered to be more severe, and therefore more critical than many of the other Category C outages studied as part of the 2010/2011 study. The impact of outages of two or more elements that resulted from a combination of two Category B outages at voltage levels of 60 kV and above were also evaluated for a number of the local area studies;

TPL-004

For this standard, selected extreme events were studied. However, during the 2008/2009 planning process, the ISO performed a detailed assessment of the most severe Category D outages in the ISO balancing authority area. The results from this analysis were documented in the 2010 transmission plan[18]. The results documented in this report satisfy the TPL-004 standard requirement 1.3.1 as well as the requirement for this 2010/2011 transmission plan.

2.3.2.5 Generation Projects

The ISO modeled a 20% renewable energy scenario for the 2015 renewable focus reliability study case. Specifically, the ISO included in its 20% RPS portfolio for the 2015 study case the renewable generation and associated transmission in the ISO queue that was in the following stages of interconnection process and was expected to be in service by 2015:

- For serial interconnection studies, both the large generation interconnection process (LGIP) and the small generator interconnection process (SGIP) – All renewable projects with all interconnection studies completed and that have either signed or are in the process of signing their interconnection agreement; and
- All remaining renewable projects in phase II of the ISO Transition Cluster (after posting of financial securities).

For 2020 renewable transmission studies, the ISO evaluated various renewable scenarios to determine needed transmission to access and deliver renewable generation to meet 33% RPS goals. Chapters 4 and 5 include detailed study assumptions, methodology and results for the 2020 33% RPS transmission studies.

2.3.2.6 Transmission Projects

[18] 2010 Final California ISO Transmission Plan at **http://www.ISO.com/2771/2771e57239960.pdf**

The study included all existing transmission projects in service and the expected future transmission projects that have been approved by the ISO for interconnection in accordance with the project approval status list in the 2010 transmission plan. In addition, generation interconnection transmission related projects that were included in executed Large Generator Interconnection Agreements (LGIA) prior to the final posting of the 2011 transmission plan study plan on March 31, 2010, were included in the study cases. Refer to Tables 8.1-1 and 8.1-2 of chapter 8 (Transmission Project Lists) of this report for the list of transmission projects modeled in the base cases.

2.3.2.7 Load Forecast

The local area load forecasts used in the study were developed by the corresponding PTOs using the CEC-approved load forecast in December 2009[19] as the starting point as the load forecast from the CEC did not provide the bus-level demand projections. The 1-in-10 load forecasts were modeled in each of the local area studies. The 1-in-5 coincident peak load forecasts were used for the northern area backbone system assessment as it covers a vast geographical area with significant temperature diversity. More details of the demand forecast are provided in the discussion sections of each of the study areas.

Light Load Conditions

The assessment evaluated the light load conditions in various parts of the ISO balancing authority area to satisfy NERC compliance requirement 1.3.6 for TPL-001, TPL-002 and TPL-003. The ISO light load conditions in various local areas of the system ranged from 35% to 50% of the summer peak load in that area. In most cases, the impacts under light load conditions were less severe than those under peak load conditions.

Some of the local areas were not evaluated for light load conditions because they were known through documentary evidence to have less severe impacts or no impacts on the system as compared to impacts under peak load conditions. The ISO staff used the discretion allowed under requirement 1.3.1 of TPL-001 and 1.3.2 of TPL-002 and TPL-003 to limit evaluation of such areas only for peak load conditions.

2.3.2.8 Reactive Power Resources

Existing and new reactive power resources were modeled in the base cases for the study to ensure realistic reactive power support capability. These resources include generators, capacitors, static var compensators (SVC) and other devices. A list of generation plants and corresponding assumptions related to each of the eight local areas are provided in further details of this chapter. The following is a listing of several key reactive power resources that were modeled in the studies:

- All shunt capacitors in the SCE service territory;

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19 http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html

- Static Var Compensators (SVCs) or Static Synchronous Compensator (STACOM) at several locations such as Potrero, Newark, Rector, Devers and Talega Substations.

For a complete list of these resources, refer to the base cases available at the ISO Market Participant Portal secured website (https://portal.ISO.com/tp/Pages/default.aspx)[20].

2.3.2.9 Operating Procedures

ISO operating procedures for both the system under normal (pre-contingency) and emergency (post-contingency) conditions were observed in this study. Table 2.3-3 summarizes major operating procedures that are utilized in the ISO controlled grid.

Table 2.3-3: Normal (pre-contingency) operating procedures

Operating Procedure	Scope
G 206	San Diego Area Generation Requirements
G 217	South of Lugo Generation Requirements
G 219	SCE Area Generation Requirements
G 233	Bay Area Generation Requirements
T 144	South of Lugo 500 kV lines
T 116	AC/DC Nomogram for N/S Flow
T 129	Fresno Area Operating Instructions (T129)
T 103	Southern California Import Transmission (SCIT)

2.3.2.10 Firm Transfers

Power flow on the major power transmission paths was considered and modeled as a firm transfer on the major import paths into the ISO BAA. In general, the northern California system has two major power transfer paths (i.e., Path 66 and Path 26). Table 2.3-4 lists the transfer capability and power flows that were modeled in each scenario on these paths in the northern area assessment for both the 2015 and 2020 base cases.

Table 2.3-4: Major Paths and Power Transfer Capabilities in the Northern California Assessment

Import Path	2015 Summer Peak	2015 Summer Off-Peak	2020 Summer Peak	2020 Summer Off-Peak
California-Oregon Intertie Flow (N-S) (MW)	4800	-3631	4800	-3665

[20] This site is available to Market Participant who has submitted a Non-Disclosure Agreement (NDA) and is approved to access the portal by the ISO.

Pacific DC Intertie Flow (N-S) (MW)	3000	-1855	3100	-1857
Path 15 Flow (S-N) MW	-534	5350	-62	5380
Path 26 Flow (N-S) MW	4000	-1052	4000	-674
Northern California Hydro % dispatch of nameplate	80%	n/a	80%	n/a

Table 2.3-5 lists the major paths in the SCE service territory in southern California and the corresponding power transfer capabilities (MW) under various system conditions as modeled in the base cases for the assessment.

Table 2.3-5: Major paths and power transfer capabilities for the SCE area assessment

Import Path	2015 Summer Peak	2015 Spring Off-Peak	2020 Summer Peak
Path 26 Flow (N-S)	3135	1942	3004
West of River	8542	7055	8048
East of River	7447	5945	6575
PDCI	3000	3000	3100
SCIT	17170	14499	15885

Table 2.3-6 lists the major paths in the SDG&E service territory in southern California and the corresponding power transfer capabilities (MW) under various system conditions as modeled in the base cases for the assessment.

Table 2.3-6: Major paths and power transfer capabilities for the SDG&E area assessment

Import Path	Path Flow (MW)	
	2015 Summer Peak	2020 Summer Peak
Midway-Los Banos (Path 15)	1038	1633
Arizona-California (Path 21)	3206	3685
Northern-Southern California (Path 26)	1180	936
IPP DC (Intermountain-Adelanto)	1823	1702
Sylmar-SCE	149	-26
IID-SCE	229	10
North of San Onofre	1809	1444
South of San Onofre	341	706
ISO-Mexico (CFE)	3	3
West of Colorado River (WOR)	4644	5969
East of Colorado River (EOR)	3474	3914

Lugo-Victorville 500 kV line	1331	1696
Eldorado-Mc Cullough 500 kV line	-137	-66
Perkins-Mead 500 kV line	310	166

2.3.2.11 Protection Systems

To help ensure reliable operation of the system, many remedial action schemes (RAS) or Special Protection System (SPS) have been installed in certain areas of the system. These protection systems trip load and/or generation upon detection of system overloads by strategically tripping circuit breakers under selected contingencies. Some SPS are designed to operate upon detecting unacceptable low voltage conditions caused by certain contingencies. Table 2.3-7 lists major new and existing SPS that were included in the study.

Table 2.3-7: A sample of protection systems modeled for the reliability assessment

No.	RAS / SPS Name	Descriptions	Study Area
1	Middletown UVLS	Trip Middletown substation load under low voltages conditions.	PG&E - North Coast/North Bay
2	Humboldt SPS	Trip load in Humboldt under low voltages conditions	PG&E - Humboldt Area
3	Alameda Overload SPS	Drops City of Alameda load following the overload of Oakland cables.	PG&E - Greater Bay Area
4	Bay Area UVLS	Trip local distribution load. When detects low 230 kV voltage at Newark, Monta Vista, San Mateo.	PG&E - Greater Bay Area
5	Bay Meadows OL SPS	Trip one or two Bay Meadows distribution feeders. After loss of any San Mateo - Bay Meadows 115 kV line.	PG&E - Greater Bay Area
6	Eastshore 230/115 kV TB #1 and #2 Overload SPS	T&LO, and initiate breaker failure on the associated transformer high and low side breakers if loading above emergency rating. Scheme is normally cut out except for specific clearances.	PG&E - Greater Bay Area
7	Evergreen - San Jose B OL	Trip San Jose CBs 112, 122 following the OL on Evergreen - San Jose B	PG&E - Greater Bay Area
8	Gilroy Energy Center SPS	Trip up to 51 MW gen at Gilroy Energy Center if OL on Llagas - Morgan Hill or Llagas - Metcalf 115 kV lines.	PG&E - Greater Bay Area
9	Grant - Eastshore OL SPS	Trip Grant feeder breakers 1105 & 1108 if OL on Grant - Eastshore #1, #2	PG&E - Greater Bay Area

No.	RAS / SPS Name	Descriptions	Study Area
10	Metcalf - El Patio OL SPS	Trip El Patio CB 142 (El Patio - SJ A) if Load > 960 A on either Metcalf - El Patio #1 or #2 115 kV line.	PG&E - Greater Bay Area
11	Metcalf SPS	Trip load and curtail generation following the loss of Moss Landing - Metcalf or Metcalf – Tesla	PG&E - Greater Bay Area
12	Monta Vista N-2 OL SPS	Trip Monta Vista - Jefferson #1 and #2 230 kV lines following loss of both Monta Vista #3 & #4 230 kV lines.	PG&E - Greater Bay Area
13	Moraga - Oakland J OL SPS	Trip Oakland J CB 122 (Jenny) if load > 750 A on Moraga – J	PG&E - Greater Bay Area
14	Newark Dumbarton OL SPS	Trip Dumbarton CB 132 if OL on Newark - Dumbarton 115	PG&E - Greater Bay Area
15	San Francisco RAS	Trip Area Load after NERC Cat D loss of area generation or transmission.	PG&E - Greater Bay Area
16	South of San Mateo SPS	Trip up to 600 MW of load in the peninsula if 115 kV line OL caused by N-2 230 kV outages.	PG&E - Greater Bay Area
17	Paso Robles UVLS	Drops load at Paso Robles Substaion to mitigate any voltage collapse concerns for the loss of Paso Robles - Templeton 70 kV line	PG&E - Los Padres Area
18	SCE's "MWD Eagle Mountain Thermal Overload Protection Scheme"	The thermal overload relay will trip Eagle Mountain-Julian Hinds if an overload is detected on the Iron Mountain-Eagle Mountain 230 kV line.	SCE
19	West of Devers Overload Protection Scheme ("WOD SPS")	The WOD SPS was put in service in June 2007. The objective of this scheme is to mitigate the existing overloads on West of Devers 230 kV lines. The WOD SPS includes tripping of two Devers 500/230 kV AA transformer banks under certain system configuration	SCE
20	South of Lugo (SOL) N-2 SPS	This remedial action scheme was put in operation in June 2005 to trip up to 3 "A" station loads (Mira Loma, Padua, and part of Chino) for a total of about 1100MW to 1400MW if any two 500 kV lines were lost on the South of Lugo path.	SCE
21	Mariposa UVLS	Trip load in the area if under voltages detected	PG&E San Joaquin Valley
22	Ashlan 230 kV UVLS	Trip load in the area if under voltages detected	PG&E San Joaquin Valley
23	McCall 230 kV UVLS	Trip load in the area if under voltages detected	PG&E San Joaquin Valley

No.	RAS / SPS Name	Descriptions	Study Area
24	Stagg UVLS	Monitor the Stagg 230 kV bus voltage and curtail load to mitigate post-contingency low voltage problems which could result from a sustained outage to the Tesla - Stagg and Tesla – Eight Mile Road 230 kV line.	PG&E - Stockton Area
25	Blythe RAS	There is an existing Blythe RAS to mitigate the overload on the lines out of Blythe 161 kV. In 2010, the Blythe I project will leave the Western Area Power Administration, Lower Colorado (WAPA LC) control area and connect to Julian Hinds 230 kV with a gen-tie line. This RAS is used to prevent low voltages or line overloads in the Iron Mountain/Eagle Mountain/Julian Hinds area by tripping the Mirage-Julian Hinds 230 kV line.	SCE
26	Low Voltage Load Shedding (LVLS) Scheme.	This remedial action scheme was put in operation in the mid-1980's to prevent a low-voltage condition resulting from the simultaneous loss of the Lugo-Mira Loma 2&3 and Lugo-Serrano 500 kV (or Lugo-Rancho Vista, after Lugo-Serrano is looped in).	SCE
27	Yolo 115 kV UVLS	Trip load in the Woodland area if under voltages detected	PG&E Scramento Area
28	Figarden 230 kV UVLS	Trip load in the area if under voltages detected	PG&E San Joaquin Valley
29	500 kV TL 50001 IV Generator SPS	Trip generation at CLR II and TDM under contingency conditions	SDG&E
30	Miguel transformer protection	Monitors the loss of transformer and the loading on the remaining transformer	SDG&E
31	Otay Mesa – Tijuana SPS	A redundant scheme is installed to protect the line from loading above its continuous rating	SDG&E
32	TL 649 69 kV SPS	An SPS to protect TL 649 from thermal overload for an outage of TL 6910	SDG&E
33	Cascade Thermal Overload Scheme	An SPS to open the Crag View-Cascade 115 kV intertie to protect thermal overload on the Cascade-Benton-Deschutes 60 kV line.	PG&E North Valley Area
34	Caribou PH Thermal Overload Scheme	An SPS to protect the Caribou-Palermo 115 kV line from thermal overload by tripping generation in the Caribou area.	PG&E North Valley Area

2.3.2.12 Control Devices

Several control devices were modeled in the study. These control devices included key reactive resources listed in Section 2.3.2.8 and the following direct current (DC) controls for the following DC transmission lines:

- DC transmission lines such as the Pacific Direct Current Interface (PDCI), Inter-Mountain power plant direct current (IPPDC), and the Trans Bay projects.

For complete details of the control devices that were modeled in the study, please refer to the base cases that are available through the ISO Market Participant Portal secured website.

2.19 SAN DIEGO GAS & ELECTRIC AREA

2.19.1 Area Description

SDG&E is a public utility that provides energy service to 3.4 million consumers through 1.4 million electric meters and more than 830,000 natural gas meters in San Diego and southern Orange counties. The utility's service area encompasses 4,100 square miles from Orange County to the Mexican border[22].

Presently, the SDG&E transmission system consists of the 500 kV Southwest Powerlink (SWPL) transmission line (North Gila - Imperial Valley-Miguel) and 230 kV, 138 kV and 69 kV transmission. When the *Sunrise Powerlink Project* is completed, presently scheduled for 2012, SDG&E will have an additional 500 kV line from the Imperial Valley substation to central San Diego to serve its load. SDG&E uses both imports and internal generation to serve the load. The geographical location of the SDG&E system is shown in Figure 2.19-1.

Figure 2.19-1: San Diego Area Illustration

The existing points of import are the South of San Onofre (SONGS) transmission path (WECC Path 44), the Miguel 500/230 kV substation and Otay Mesa –Tijuana 230 kV transmission line.

Historically, the SDG&E import capability was 2850 MW with all facilities in-service and 2500 MW with SWPL out-of-service. When the proposed *Sunrise Powerlink Project* is built (scheduled in-service for June 2012), import capability will be increased by at least another 1000 MW and the cut-plane of import will change by having the Imperial Valley-Suncrest 500 kV line flow added to the import into SDG&E.

[22] These numbers are provided by SDG&E in the 2008 Transmission Expansion Plan

In addition to import, the SDG&E area is served by local generation. Existing generation within the SDG&E system is comprised of combustion turbines, QF, steam turbines (ST) at Encina, the combined cycle plants at Palomar Energy (PEN) and Otay Mesa Energy Center and one wind farm. Only generation that is under construction or that has received regulatory approvals was modeled.

The SDG&E transmission system consists of 500 kV SWPL transmission line (North Gila - Imperial Valley-Miguel) and 230 kV, 138 kV and 69 kV transmission. The 500 kV substations include Imperial Valley 500/230 kV and Miguel 500/230/138/69 kV.

The 230 kV system extends from the Talega substation and SONGS in Orange County in the north to the Otay Mesa substation in the south near the Mexican border. 230 kV transmission lines are with an outer loop located along the Pacific coast and around downtown San Diego.

The 138 kV transmission system underlies the 230 kV system from the San Luis Rey 230/138/69 kV Substation in the north to the South Bay and Miguel substations in the south. There is also a radial 138 kV arrangement with five substations interconnected to the Talega 230/138/69 kV substation in Orange County.

SDG&E sub-transmission system consists of numerous 69 kV lines arranged in a network configuration. Rural customers in the eastern part of the San Diego County are served exclusively by a 69 kV system and often by long lines with low ratings.

2.19.2 Area Specific Assumptions and System Conditions

The SDG&E area study was performed in accordance with the general study assumptions and methodology described in section 2.3. The ISO's secured website lists the contingencies that were evaluated as a part of this assessment. In addition, specific assumptions and methodology applied to the SDG&E area study are provided below in this section.

Generation

The studies performed for the heavy summer conditions assumed all available internal generation being dispatched at full output except for the South Bay power plant that was assumed to be retired and Kearney peakers which were assumed to be retired beyond 2014. The Category B contingency studies were also performed for one generation plant being out-of-service. The largest single generator contingencies were assumed to be the whole Otay Mesa Energy Center or PEN Center. These two power plants are combined-cycle plants; therefore, an outage of the whole plant has a high probability.

Existing generation included all five Encina steam units. They were assumed to be available during peak loads. A total of 946 MW of generating capacity can be dispatched based on the maximum capacity of each generating unit. PEN, owned by SDG&E, began commercial operation in April 2006. This plant is modeled at 565 MW for summer peak load reliability assessment.

South Bay power plant (689 MW and a 13 MW gas turbine) was assumed to be retired for the 2011-2015 and 2020 study scenarios. South Bay units 3 and 4 are already retired and the RMR status of units 1 and 2 was terminated on December 31, 2010.

The new combined cycle Otay Mesa power plant started commercial operation in October 2009. It was modeled in the studies with the maximum output of 603 MW.

There are several combustion turbines in San Diego. Cabrillo II owns and operates all but two of the small CTs in SDG&E's territory. Of the two not operated by Cabrillo II, Cabrillo I operates one at the Encina plant and the second was operated by Dynegy at the South Bay power plant. The CT at South Bay was assumed to be retired in the study, since it is scheduled to retire when the South Bay power plant retires. A total of 200 MW of generating capacity from CTs was modeled as dispatched during peak summer conditions.

QFs were modeled with the total output of 180 MW. Power contract agreements with the QFs do not obligate them to generate reactive power. Therefore, to be conservative, all QF generation explicitly represented in power flow cases was modeled with a unity power factor assumption.

Existing peaking generation modeled in the power flow cases included Calpeak Peakers located near Escondido (42 MW), Border (42 MW), and El Cajon (42 MW) substations, two Larkspur peaking units located next to Border substation with summer capacity of 46 MW each, two peakers owned by MMC located near Otay (35.5 MW) and Escondido (35.5 MW) substations, two SDG&E Peakers at Miramar substation (MEF), 46 MW each, El Cajon Energy Center (48 MW) and Cabrillo Power peakers at Miramar (36 MW aggregate) and El Cajon GT (13 MW). New peaking generation modeled in the studies included two units, 94 MW total, at Orange Grove adjacent to 69 kV Pala substation. The Orange Grove peaking plant (94 MW) has currently completed construction and has started commercial operation in 2010.

Renewable generation included in the model is the 50 MW Kumeyaay Wind Farm that began commercial operation in December 2005, Lake Hodges pump-storage plant (40 MW) that is presently under construction and planned to start operation in July 2011, and a future Bull Moose Biomass plant (27 MW) which is planned to be in-service by May 2011. The Bull Moose and Lake Hodges plants were modeled in the power flow cases, but if these projects do not materialize, these units will not be modeled in future study cases.

In addition to the generation plants internal to San Diego, there is 1,070 MW of existing thermal power plants connected to the 230 kV bus of the Imperial Valley 500/230 kV substation. There are several renewable generation projects (solar and wind) expected to be developed in this area. These are modeled and handled in the 33% renewable study carried out as part of this transmission plan.

The SONGS was modeled with two units on-line at maximum output for the summer peak load conditions.

Internal generation in San Diego modeled in the case is summarized in Table 2.19-1.

Table 2.19-1: Generation plants in the SDG&E area

Generation Plants	Max. Capacity (MW)	Note
South Bay 1	145	assumed retired
South Bay 2	149	assumed retired
South Bay 3	174	assumed retired
South Bay 4	221	assumed retired
Encina 1	106	
Encina 2	103	
Encina 3	109	
Encina 4	299	
Encina 5	329	
Palomar	541	
Otay Mesa	573	
South Bay GT	13	assumed retired
Encina GT	14	
Kearny GT1	15	assumed retired
Kearny 2AB (Kearny GT2)	55	assumed retired
Kearny 3AB (Kearny GT3)	57	assumed retired
Miramar GT 1	17	
Miramar GT 2	16	
El Cajon GT	13	
Goalline	48	
Naval Station	47	
North Island	33	
NTC Point Loma	22	
Sampson	11	
NTC Point Loma Steam turbine	2.3	
Ash	0.9	
Cabrillo	2.9	
Capistrano	3.3	
Carlton Hills	1.6	
Carlton Hills	1	
Chicarita	3.5	
East Gate	1	
Kyocera	0.1	
Mesa Heights	3.1	
Mission	2.1	
Murray	0.2	
Otay Landfill I	1.5	

Generation Plants	Max. Capacity (MW)	Note
Otay Landfill II	1.3	
Covanta Otay 3	3.5	
Rancho Santa Fe 1	0.4	
Rancho Santa Fe 2	0.3	
San Marcos Landfill	1.1	
Shadowridge	0.1	
Miramar 1	46	
Larkspur Border 1	46	
Larkspur Border 2	46	
MMC - Electrovest (Otay)	35.5	
MMC - Electrovest (Escondido)	35.5	
El Cajon/Calpeak	42	
Border/Calpeak	42	
Escondido/Calpeak	42	
El Cajon Energy Center	48	
Miramar 2	46	
Orange Grove	94	
Kumeyaay (NQC)	8.3	
Bullmoose (NQC)	27	
Lake Hodges Pumped Storage	40	

Load Forecast

Loads within the SDG&E system reflect a coincident peak load for 1-in-10-year heat wave conditions. The load for the year 2015 was assumed at 5234 MW and transmission losses were 114 MW. The load for the year 2020 was assumed at 5554 MW and transmission losses were 117 MW. SDG&E substation loads were assumed according to the data provided by SDG&E and scaled to represent assumed load forecast. The total load in the power flow cases was modeled based on the load forecast by the CEC. Table 2.19-2 summarizes load in SDG&E and the neighboring areas and SDG&E import modeled for the study horizon.

Table 2.19-2: Load and losses in SDG&E study

PTO	2011		2012		2013		2014		2015		2020	
	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW
SDG&E	4937	97	5034	86	5123	90	5172	102	5234	114	5554	117
SCE	25585	471	26245	408	26245	409	27449	417	27449	412	28432	465

PTO	2011		2012		2013		2014		2015		2020	
	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW
IID	1056	32	1080	46	1107	47	1131	41	1163	43	1308	45
CFE	2223	32	2935	35	2935	35	2820	34	2820	34	3413	49
SDG&E Import	2101		2255		2365		2302		2472		2787	

Power flow cases for the study modeled a load power factor of 0.992 lagging at nearly all load buses. This number was used because SCADA-controlled distribution capacitors are installed at each substation with sufficient capacity to compensate for distribution transformer losses. The 0.992 lagging value is based on historical system power factor during peak conditions. The exceptions listed below were modeled using power factors indicative of historical values. This model of the power factors was consistent with the modeling by SDG&E for planning studies. Periodic review of historical load power factor is needed to ensure that planning studies utilize realistic assumptions.

- Naval Station Metering (bus 22556): 0.707 lagging (this substation has a 24 MVAr shunt capacitor);
- Creelman (bus 22152): 0.992 leading; and
- Descanso (bus 22168): 0.901 leading.

2.19.3 Study Results and Discussions

The ISO's assessment of the SDG&E transmission system identified two overloads that may occur under normal system conditions with all facilities in-service. One overload was on the Boulevard – Crestwood 69 kV line starting after 2015 under Category A conditions. The other Category A overload was observed on Mesa Heights – Mission 69 kV line starting in 2020.

None of the buses resulted in voltages below the limits specified in the reliability criteria under the Category A performance requirements.

The assessment also identified 25 transmission facilities that may overload under Category B contingency conditions under an assumption that all available generation is dispatched. There were additional 58 facilities that may overload under Category C contingency conditions. Category B contingency conditions included single facilities contingencies, as well as contingencies of single transmission facilities with one generation unit out-of-service. Category C contingencies included contingencies of two facilities and conditions when a transmission facility was out-of-service followed by another single transmission facility outage.

The ISO studies identified voltages below permitted levels on seven 69 kV buses for Category B contingencies. Twelve 69 kV load buses were identified as having voltage deviations that did not meet the reliability criteria for Category B contingencies.

Most of the overloads observed in the analysis of the off-peak case were already seen in the peak case analysis. Only one additional facility did not meet the Category B contingency performance requirement.

Transient stability studies did not show any reliability performance concerns for the Category B and Category C contingencies studied. The studies also did not identify any voltage stability (reactive margin) concerns.

Studies of the extreme contingencies (Category D) did not identify potential cascading contingencies.

2011 through 2015 SDG&E Area Assessment Summary

For the overall SDG&E transmission and sub-transmission systems, the 2015 studies identified the need to:

- Strengthen the 69 kV system in Barrett area;
- Mitigate the 69 kV system issues in El Cajon area using generation;
- Strengthen the 69 kV system in Kearney area;
- Strengthen the 69 kV system in Melrose area;
- Reconductor South Bay – Sweetwater 69 kV line; and
- Mitigate the 69 kV system issues in Sycamore area using Miramar generation.

2020 SDG&E Area Assessment Summary

For the overall SDG&E transmission and sub-transmission systems, the 2020 studies identified the need to implement the following, in addition to the upgrades/mitigations listed in the 2015 studies:

- Dispatch one Orange Grove peaking unit for peak load conditions (to prevent emergency overload of the San Luis Rey-Morro Hill 69 kV line); and
- Consider switching options or reconductoring to mitigate an overload on Talega Tap – Laguna Niguel 138kV line.

The study evaluated the system reliability of SDG&E area under NERC/WECC and the ISO Category A, B, C and D contingencies.

Power Flow Study Results

TPL 001: System Performance under Normal Conditions

For the summer peak cases, there were two 69 kV transmission lines with an identified overload with all facilities in service – Boulevard – Crestwood and Mesa Heights - Mission. The ISO studies showed overloads beyond 2019 over the normal rating.

None of the buses demonstrated voltages below the limits specified in the reliability criteria under Category A performance requirements.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (N-1[23]/G-1)

For the summer peak cases, there were 25 facilities identified with thermal overloads for contingencies of a single transmission facility or a single transmission facility with one generator out-of-service. The overloaded facilities were the following:

- Boulevard – Crestwood 69 kV line;
- Boulder Creek Tap – Descanso 69 kV line;
- Boulder Creek Tap – Santa Ysabel 69 kV line;
- Descanso – Glencliff Tap 69 kV line;
- Warners – Rincon 69 kV line;
- El Cajon – Los Coches 69 kV line;
- Mesa Heights – Mission 69 kV line;
- Kearney – Mission 69 kV line;
- Mission – Clairmont 69 kV line;
- Melrose – Melrose Tap 69 kV line;
- Melrose – San Luis Rey 69 kV line;
- Morro Hill Tap – San Luis Rey 69 kV line;
- Pendleton – San Luis Rey 69 kV line;
- Pomerado – Sycamore 69 kV line 1;
- Pomerado – Sycamore 69 kV line 2;
- Poway – Rancho Carmel 69 kV line;
- South Bay – Sweetwater 69 kV line;
- South Bay – Montgomery Tap 69 kV line;
- Sweetwater – Montgomery Tap 69 kV;
- Sweetwater – Sweetwater Tap 69 kV line;
- Sycamore – Scripps 69 kV line;
- Talega Tap – Laguna Niguel 138kV line;
- Pala – Monserate Tap 69 kV line;
- Mission 138/69 kV bank 50; and
- Los Coches 138/69 kV bank 50.

These overloads and the proposed mitigation measures are summarized in Appendix A.

For the off-peak cases, there was one additional overload for Category B contingency of Imperial Valley 500/230 kV transformer bank #80. Only two existing 500/230 kV transformer banks were modeled at Imperial Valley. Installation of the third bank to be implemented with a generation project interconnection will mitigate this overload. Prior to the bank installation, the overload may be mitigated by generation dispatch.

[23] N-1 is a single transmission circuit outage.

Under Category B contingencies and the peak load conditions, there were seven 69 kV load buses with voltages below what is allowed by the criteria, and eleven 69 kV load buses with voltage deviations not meeting the criteria requirements.

The following buses had low voltage for Category B contingencies:

- Barrett 69 kV;
- Boulder Creek 69 kV;
- Boulevard 69 kV;
- Cameron 69 kV;
- Descanso 69 kV;
- Glencliff 69 kV; and
- Crestwood 69 kV.

The following buses had large voltage deviations:

- Barrett 69 kV;
- Boulder Creek 69 kV;
- Borrego 69 kV;
- Boulevard 69 kV;
- Cameron 69 kV;
- Crestwood 69 kV;
- Descanso 69 kV;
- Glen Cliff 69 kV;
- Narrows 69 kV;
- Santa Ysabel 69 kV;
- Warners 69 kV; and
- Poway 69 kV.

No voltage concerns were identified for the off-peak conditions. These voltage concerns and the proposed mitigation measures are summarized in Appendix A.

TPL 003: System Performance Following Loss of Two or More BES Elements

Category C contingencies studied included:

- Outage of a single transmission facility with generation adjusted followed by another single facility outage (N-1-1);
- Outage of two transmission lines in the same corridor (N-2);
- Stuck circuit breaker; and
- Outage of a bus or a bus section.

For the summer base cases, there are 58 facilities with identified thermal overloads for Category C contingencies in addition to the facilities that overload for Category B contingencies. These overloads and the proposed mitigation measures are summarized in Appendix A.

None of the buses experienced voltages below the standard's requirement for Category C contingency.

TPL 004: System Performance under Extreme Events

As a Category D contingency, a common corridor outage of the transmission lines north of Miguel was studied. This outage is plausible, even if very unlikely, since the lines are in the common corridor. Transmission lines in the North-of-Miguel corridor include:

- Miguel-Sycamore Canyon 230 kV;
- Miguel-Mission #1 and #2 230 kV;
- Otay Mesa-Sycamore Canyon 230 kV;
- Miguel-Los Coches 138 kV and 69 kV; and
- Miguel-Jamacha #1 and #2 69 kV.

The case converged with no indication of cascading failures or major overloads for the system conditions studied.

Another common corridor contingency involving more than two transmission circuits is an outage of transmission lines from San Onofre to San Luis Rey. This transmission corridor includes the following lines:

- San Onofre-San Luis Rey 230 kV #1,2, and 3

The studies of this common corridor Category D contingency for the peak summer conditions of 2020 showed that there would be no cascading contingencies and no overloads for the system conditions studied.

Also, a Category D outage of the transmission lines north of San Onofre was studied. This contingency includes the following transmission lines:

- San Onofre-Talega 230 kV #1 and #2;
- Talega-San Mateo 138 kV;
- Talega-Japanese Mesa 69 kV; and
- San Mateo-Laguna Niguel 138 kV.

The studies did not show any possibility of cascading contingencies. No overloads were observed for this Category D contingency under the assumed system conditions.

Category D contingencies of loss of major power plants in SDG&E were also run as part of the reliability assessment. Loss of Otay Mesa, Palomar, Encina and SONGS generation plants were tested one at a time. These extreme contingencies did not show possibility of cascading contingencies.

NUC-001: System Performance under scenarios that can affect SONGS

The technical studies were conducted in compliance with the NUC-001 standards annually as part of the transmission plan. Post-transient governor power flow and transient stabilities were conducted to assess the performance related to SONGS under normal and emergency conditions. In this planning cycle, the studies were conducted on the following scenarios:

- 2011 summer peak; and
- 2015 summer peak.

Several contingencies were run in SDG&E area for thermal, voltage and stability concerns. These contingencies included:

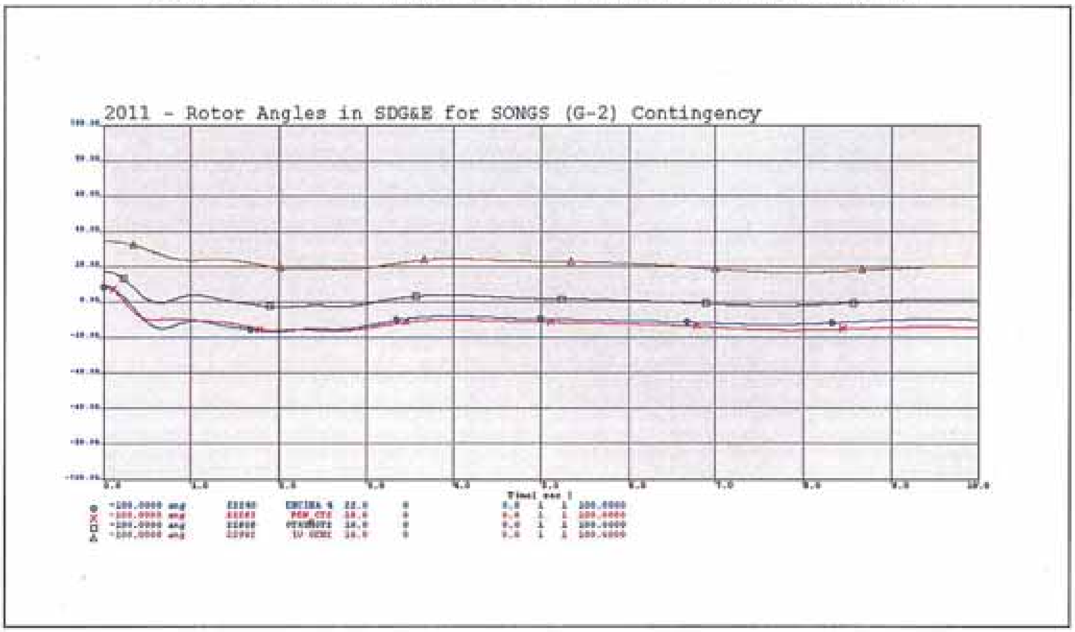
- Loss of a single SONGS unit (G-1);
- Loss of two SONGS units (G-2);
- All critical contingencies of transmission lines connected to SONGS (Category B, C and D);
- Loss of major generation plants in SDG&E area;
- Loss of critical transmission lines and interties in SDG&E system;
- Critical bus section contingencies in SDG&E area; and
- Loss of entire load at Bernardo substation (largest load block in SDG&E's service territory according to the information provided in the base case).

The base cases modeled all transmission circuits connected to SONGS switchyard with the status normally in-service. The study results showed that:

- The steady state voltage at SONGS 230 kV switchyard was 230 kV under 2011 summer peak conditions and 230 kV under 2015 summer peak conditions. This is within the range specified by Transmission Control Agreement for SONGS (218kV to 234kV); and
- The SONGS generator is regulating the 230 kV bus voltage to 1.00 per Unit in 2011 summer peak case and in 2015 summer peak case.

The study results from various studies show that there are no thermal overloads, voltage or stability concerns related to the SONGS units under normal or emergency conditions. The following plots for two of the most severe contingencies and for a sudden loss of load demonstrate that there are no stability concerns related to SONGS units.

Figure 2.19-2: Rotor Angles in SDG&E for SONGS (G-2) Contingency



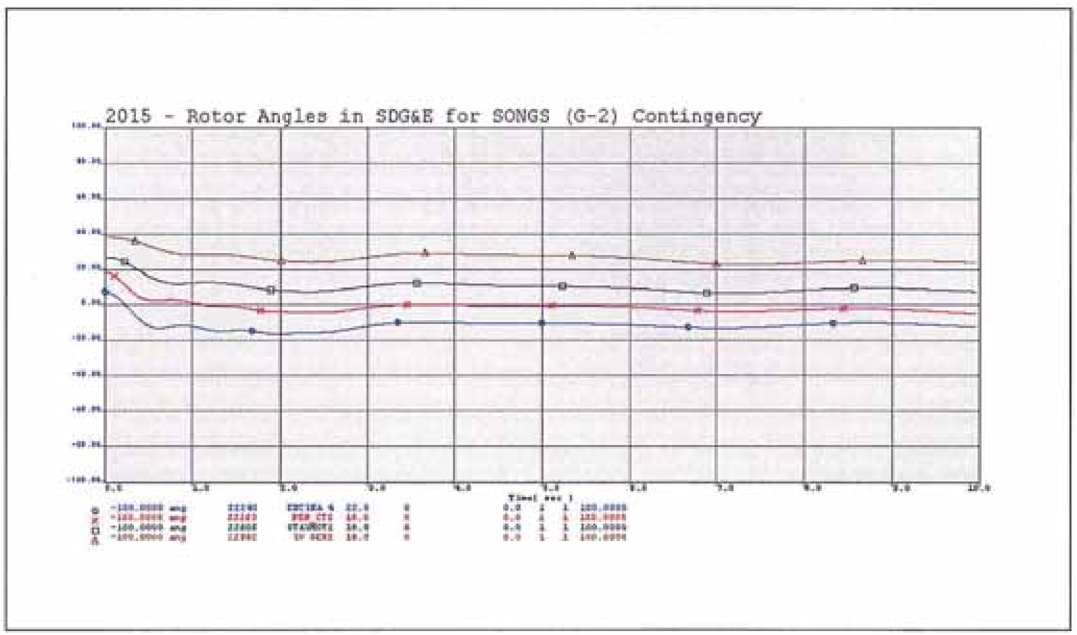


Figure 2.19-3: System Performance under SWPL and (SWPL+Sunrise) Contingency

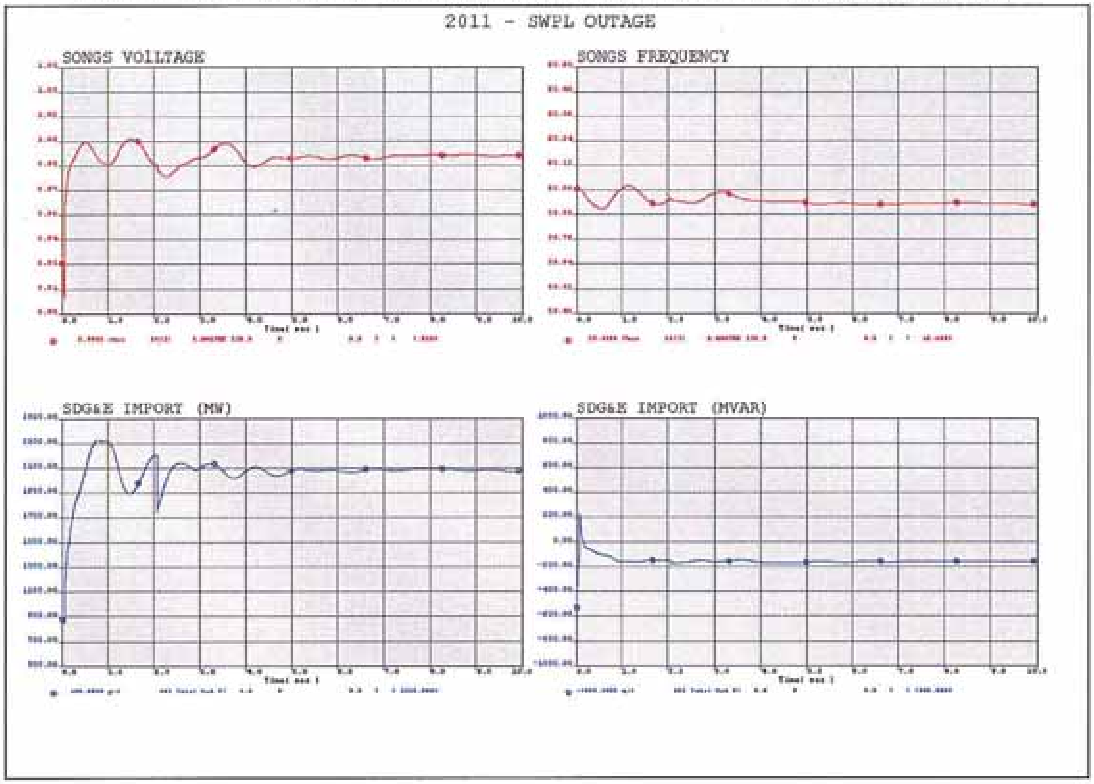
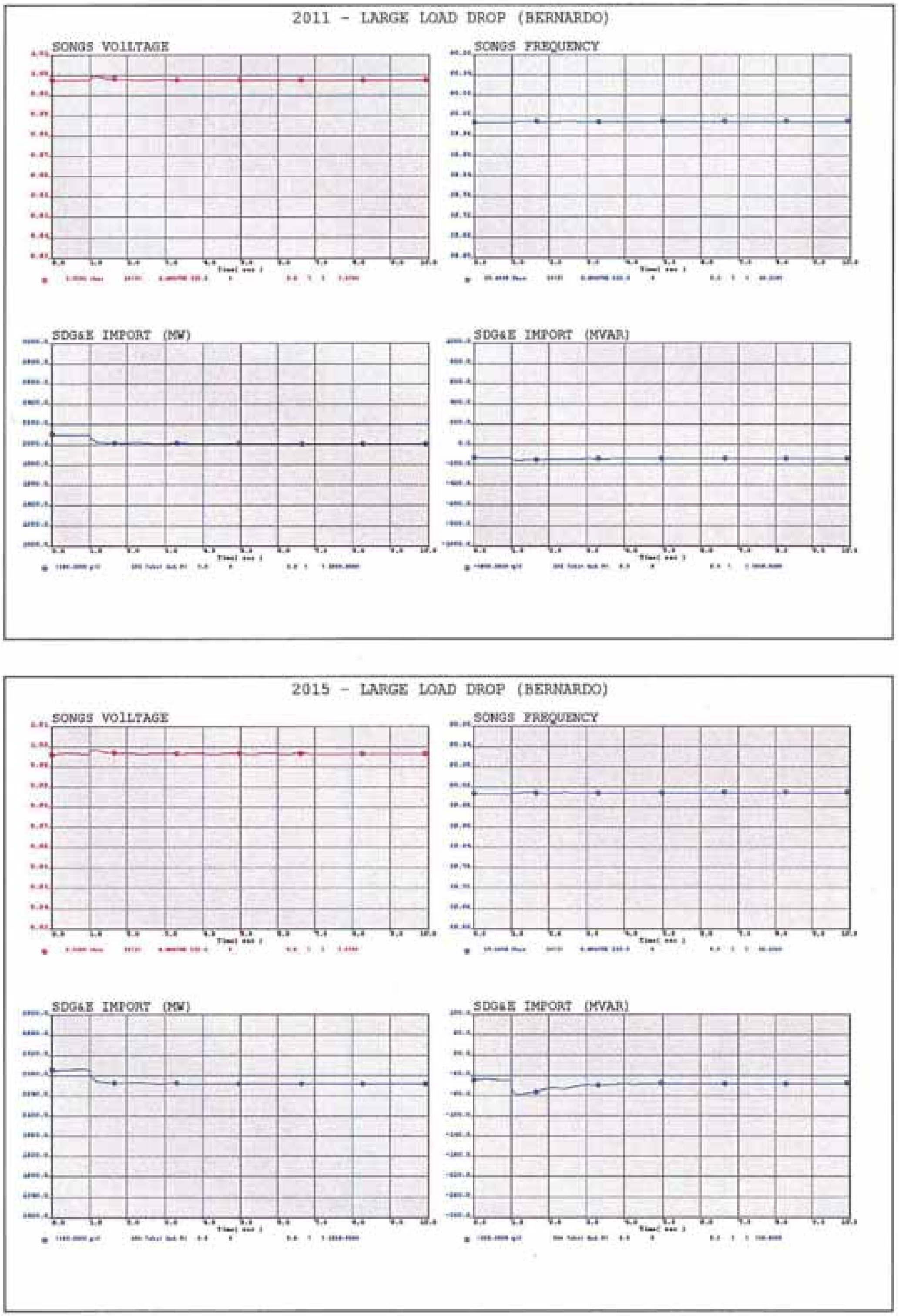


Figure 2.19-4: System Performance under Sudden Loss of Load



Transient Stability Studies

All major 500 kV and 230 kV contingencies were studied for the year 2020. Scenarios analyzed included critical Category B, C, and D contingencies based on historical and expected operation. Three-phase faults were modeled on the sending end bus of transmission lines. Duration of the fault was modeled as four cycles for 500 kV and six cycles for 230 kV. The faults were cleared by opening of the lines. The contingencies that were studied included:

- Imperial Valley-Miguel 500 kV with and without CFE cross trip;
- Hassayampa-North Gila 500 kV;
- Imperial Valley-North Gila 500 kV;
- Palo Verde-Devers 500 kV;
- Imperial Valley-Suncrest 500 kV (planned);
- Intermountain-Adelanto DC;
- Pacific DC Intertie bipolar;
- Sycamore-Suncrest 230 kV (planned) #1 and #2;
- Miguel-Mission #1 and #2;
- North of Miguel corridor;
- Palomar-Escondido #1 and #2 230 kV;
- Palomar-Encina 230 kV;
- Palo Verde-Devers 500 kV;
- Lugo-El Dorado-Mohave 500 kV;
- SONGS generator #2;
- Palo Verde generator #2;
- Diablo generators #1 and 2;
- SONGS generators #2 and #3; and
- Palo Verde generator #1 and #2.

No unacceptable performance levels were found. The analysis indicates acceptable transient stability performance for all of the contingencies.

Studies of the Category D outage North of Miguel simulated a three-phase six-cycle fault on the Miguel 230 kV bus cleared by opening all transmission lines north of Miguel: Miguel-Sycamore Canyon 230 kV, Miguel-Mission #1 and #2 230 kV, Otay Mesa-Sycamore Canyon 230 kV, Miguel-Los Coches 138 kV and 69 kV and Miguel-Jamacha #1 and #2 69 kV. The study showed that the system was stable with acceptable transient stability performance.

Post Transient and Voltage Stability Studies

Post-transient studies for the Imperial Valley-Miguel 500 kV outage did not show any problems for the cases studied even without SPS. This can be explained by the addition of the *Sunrise Powerlink Project*, starting with 2012 period as provided by SDG&E. Studies of all Category B contingencies in the San Diego area with the SDG&E load increased by 5% in 2020 and the import to San Diego increased by 5% in 2020 did not show any need for additional reactive support due to insufficient reactive margin.

Voltage stability analysis was also performed for the Category D outage of North of Miguel. This outage was studied for the case of 2020. This contingency did not show any need for additional reactive support or did not result in any overloads or under-voltage problems.

Impact of the SDG&E Contingencies on the Neighboring Systems

Historically, Imperial Valley-Miguel 500 kV outage caused overloads in the CFE system. These overloads are mitigated by cross tripping either Imperial Valley-La Rosita or Otay Mesa-Tijuana 230 kV lines in case of overload via using an automatic SPS. Addition of the *Sunrise Powerlink Project* will reduce loading concerns in the CFE with the Imperial Valley-Miguel outage. Power flow and post-transient (governor power flow) studies for 2011 through 2015 as well as for 2020 did not show overloads on the CFE system for the Imperial Valley-Miguel outage. Existing RAS for the Imperial Valley-Miguel outage also trips all generation units connected to the Imperial Valley 230 kV bus. The ISO recommends revision of the existing RAS when the *Sunrise Powerlink Project* comes into service because such extensive generation tripping may not be needed with the additional 500 kV transmission line.

2.19.4 Recommended Solutions for Facilities Not Meeting Thermal and Voltage Performance Requirements

In this section, study results and proposed mitigation plans for the San Diego area under each category of the planning standards are shown.

Normal Conditions (TPL 001)

For the summer peak cases, there were two 69 kV transmission lines that were expected to overload with all facilities in service – Boulevard – Crestwood 69 kV line and Mesa Heights – Mission 69 kV line. These lines may overload for Category B and C contingencies as well. Both the overloads show up between 2015 and 2020. The Boulevard – Crestwood 69 kV line overload will be mitigated by a project submitted by SDG&E for looping in TL625 (Loveland – Barrett Tap 69 kV line) line into Loveland substation. This project is needed and described in detail under the Barrett 69 kV Area discussion in the section below. Also, a proposed terminal equipment upgrade will take care of this problem. The Mesa Heights – Mission 69 kV line overload can be mitigated by dispatching Miramar peakers and SDG&E submitted a project to reconductor this line as part of Kearney area upgrades. The project is needed and discussed in detail under Kearney 69 kV Area discussion in the section below.

There were no buses with voltage below the limits specified in the reliability criteria under the Category A performance requirements in 2020.

Emergency Conditions – Loss of a Single BES Element (TPL 002)

Power flow studies were performed for N-1 conditions (Category B) with all major power plants in-service and for N-1, G-1 conditions with the Otay Mesa or PEN generation out. Outage of the Otay Mesa power plant is the largest G-1 contingency in San Diego. Each of Category B contingencies was studied for the years 2011 through 2015 as well as for 2020. The power flow studies of Category B contingencies identified the following overloads.

500/230 kV System

No overloads or voltage concerns were identified on the 500 kV or 230 kV systems in the cases studied.

138 kV System

Orange County Area

Talega Tap – Laguna Niguel 138kV line overload was observed for an outage of the parallel Talega - Pico 138 kV line starting in 2020. SDG&E submitted a project, TL13835B Laguna Niguel, - Talega Tap Mitigation, to reconductor the line. The ISO is considering reconductoring as a conceptual mitigation. Because the overload seen in 2020 is only 1%, the ISO recommends further evaluation in a future planning cycle.

Los Coches 138/69 kV bank #50

Los Coches 138/69 kV bank 50 may experience an overload for the loss of Los Coches 138/69 kV bank 51. The observed Category B overload was 5% in 2020, and will be higher with non-simultaneous peak load in Los Coches area. Existing rating of bank 50 is 180 MVA. The ISO identified Category B overloads starting in 2014 under non-simultaneous peak load assumption. Generation connected to El Cajon is not sufficient to mitigate this problem for the duration of the study window. A project submitted by SDG&E in the 2010 request window, Upgrade Los Coches 138/69 kV Bank 50, will replace the existing 180 MVA bank with a new 224 MVA bank, with proposed in-service date of 2013. The ISO has determined that this reliability project is needed.

69 kV System

Barrett 69 kV Area

This area may experience four overloads for the loss of a single element:

- Boulder Creek Tap - Descanso 69 kV line;
- Boulder Creek Tap – Santa Ysabel 69 kV line;
- Descanso – Glencliff Tap 69 kV line; and
- Warners – Rincon 69 kV line.

All these elements become overloaded for the same contingency of the 3-terminal TL625 (Loveland – Barrett – Descanso 69 kV line) starting in 2015. Low voltages and voltage deviations are also observed due to this contingency. Also, an L-1/G-1 contingency of Loveland – Barrett – Descanso 69 kV line and Otay Mesa power plant causes following undervoltages in this area:

- Barrett 69 kV;
- Boulder Creek 69 kV;
- Boulevard 69 kV;
- Cameron 69 kV;
- Descanso 69 kV;
- Glencliff 69 kV; and
- Crestwood 69 kV.

Contingency of Loveland – Barrett – Descanso 69 kV line also creates voltage deviations at following buses in this area:

- Barrett 69 kV;
- Boulder Creek 69 kV;
- Borrego 69 kV;
- Boulevard 69 kV;
- Cameron 69 kV;
- Crestwood 69 kV;
- Descanso 69 kV;
- Glen Cliff 69 kV;
- Santa Ysabel 69 kV; and
- Warners 69 kV.

In addition, a contingency of Warners – Narrows 69 kV line creates voltage deviation problem at Narrows 69 kV bus.

The proposed solution is to remove Barrett Tap and create two new lines: Loveland-Descanso 69 kV and Loveland-Barrett 69 kV. This upgrade mitigates overloads as well as undervoltage and voltage deviation problems. This solution appears to be more effective than reconductoring all of the overloaded line sections. SDG&E's proposed in-service date is 2013 which should mitigate this potential problem in time. The ISO has determined that the need to eliminate Barrett tap and loop-in TL625B into Loveland substation exists and is addressed by the *TL625B Loop-in, Loveland – Barrett Tap Project* submitted by SDG&E in the 2010 request window with proposed in-service date of 2013. In the interim the ISO is authorizing the advancement of Barrett and Crestwood 69 kV capacitor installation to mitigate the voltage deviation problem in Barrett area. These capacitors are part of a previously approved project, *New and/or Upgrade 69 kV Capacitors* (approved as a part of 2010 transmission plan).

Request Window Submission – Barrett Interim Solution

Another project submitted in this area was *Barrett Interim Solution* by TTS. The project scope included installation of -40/+50 MVAr SVC at Barrett 69 kV substation (proposed in-service date of October, 2012). The need identified by this project will be mitigated by a long-term project (TL625B loop-in) with a proposed in-service date of June, 2013, which was deemed to be a needed reliability upgrade. ISO tariff section 24.4.6.2 provides that the PTO with service territory in which the transmission upgrade or addition deemed needed under this section 24 will have the responsibility to construct, own and finance and maintain such transmission upgrade or addition. The ISO evaluated the *Barrett Interim Solution* to determine whether SDG&E should pursue this alternative. The ISO found that the interim need is best mitigated by advancing the previously approved installation of capacitors at Barrett 69 kV and Crestwood 69 kV substations. The advancement of capacitors is more cost effective than the *Barrett Interim Solution*, hence the *Barrett Interim Solution* is not needed.

Request Window Submission – TL682 Warner-Rincon Reconductor Project

SDG&E submitted a project, the *TL682 Warner-Rincon: Reconductor Project* to mitigate the overload on Rincon – Warner 69 kV line. The project *TL625B Loop-in, Loveland – Barrett Tap* mitigates this overload and is more cost effective compared to reconductoring the line. Hence the *TL682 Warner-Rincon: Reconductor Project* is not needed.

El Cajon – Los Coches 69 kV line

This line may become overloaded for the contingency of Los Coches – Granite Tap – Miguel 69 kV line starting in 2014. The overload was observed only under a high-import scenario which was higher than the feasible import level observed in the 33% renewable scenario. SDG&E proposed the *Reconductor TL631, El Cajon-Los Coches Project* to mitigate this problem. The ISO studies demonstrated that EL Cajon peakers can sufficiently mitigate this concern for the study horizon. The need for this project will be evaluated in the next planning cycle. Instead of reconductoring this line, the ISO recommends using El Cajon peakers to mitigate any overload issue.

Kearney 69 kV Area

Three lines in Kearney 69 kV area may become overloaded for the loss of a single element.

- Mesa Heights – Mission 69 kV line;
- Kearney – Mission 69 kV line; and
- Mission – Clairmont 69 kV line.

For the loss of one of these three lines, the remaining lines become overloaded starting in 2015. Kearney peakers and Miramar peakers can be used to mitigate these overloads. The site lease for Kearney peakers is going to expire in 2013, and there are no plans to re-power the site. Miramar peakers are sufficient to mitigate this problem only up to 2017. Starting in 2017 and beyond, to mitigate these overloading concerns, SDG&E submitted projects to reconductor 3 lines (Mission - Kearney 69 kV, Mission – Clairmont 69 kV and Mission –

Mesa Heights 69 kV), with a proposed in-service date of 2015. The ISO finds these projects are needed to address the identified reliability concerns.

SDG&E also proposed the *Upgrade Mission 138/69 kV Transformer Banks 51 and 52 Project*. This overload on Mission banks 51 and 52 for the loss of the bank 50 may show up in 2020 as a 3% overload. The proposed in-service date for this project is June 2015, assuming an approval during 2010/2011 planning cycle. Because the overload does not occur until 2020, the ISO will evaluate the proposed project in a future planning cycle.

Melrose 69 kV Area

Two lines in Melrose area overload following the loss of a single element:

- Melrose – Melrose Tap 69 kV line; and
- Melrose – San Luis Rey 69 kV line.

Contingency of San Luis Rey – Melrose 69 kV line causes these overloads starting around 2015. Reconductoring these lines was considered by the ISO, but looping TL694A (San Luis Rey – Morro Hill) into Melrose substation solves these issues as well as one overload in Pendleton 69 kV area. This project was submitted by SDG&E in the 2010/2011 request window as the *TL694A San Luis Rey-Morrow Hills Tap: Reliability Project* with a proposed in-service date of 2012. It is the most cost effective solution and the ISO has determined that the project is needed.

Other reconductor projects proposed by SDG&E and considered by the ISO were the *TL693 San Luis Rey-Melrose: Reconductor Project*, the *TL694A San Luis Rey-Morrow Hills Tap: Reliability* Project and the *TL680B – Melrose-Melrose Tap: Reconductor Project*. These three projects were found not to be needed because *TL694A San Luis Rey-Morrow Hills Tap: Reliability Project* mitigates all these overloads and is more cost effective than reconductoring individual lines.

Pendleton 69 kV Area

This area experienced two overloads for the loss of a single element. The first overload is seen on Morro Hill Tap – San Luis Rey 69 kV line for the loss of Pendleton – San Luis Rey 69 kV line starting in 2013. This overload can be mitigated by dispatching Orange Grove peakers. But the approval of TL694A loop-in into Melrose substation solves this overload issue as mentioned in the Melrose 69 kV area discussion above.

Another overload observed in this area is Pendleton – San Luis Rey 69 kV line for the loss of Monserate – Morro Hill – San Luis Rey 69 kV line. SDG&E submitted a project -' *TL6912 - Reconductor San Luis Rey-Pendleton*'. This overload may show up in 2020 with an extent of only about 1%. The ISO recommends using Pala generators to mitigate this overload. The need for this upgrade will be evaluated again during the next planning cycle.

Pomerado 69 kV Area

Three lines in this area show overloads for the loss of a single element

- Pomerado – Sycamore 69 kV line 1;
- Pomerado – Sycamore 69 kV line 2; and
- Poway – Rancho Carmel 69 kV line.

Loss of Pomerado – Sycamore 69 kV line 1 or 2 overloads the remaining line. Poway – Rancho Carmel 69 kV line gets overloaded for the loss of Sycamore – Artesian 69 kV line. All these overloads are seen in 2015 study case. The ISO considered the option of reconductoring these three lines. SDG&E also submitted a project to construct a new 69 kV line between Sycamore and Bernardo substations. This line will utilize the vacant side of the towers for TL13820 and 13825. This new Sycamore – Bernardo 69 kV line would eliminate the need to reconductor three aforementioned lines. SDG&E submitted two projects: *TL648, Poway – Rancho Carmel: 69 kV Reconductor Project* and *TL6915 & TL6924 Sycamore-Pomerado #1 & #2: Reconductors Project* to reconductor the three lines mentioned here. Building a new Sycamore – Bernardo 69 kV line is a more cost effective alternative and will improve the outlet capability of Sycamore substation. The ISO has determined that building a new Sycamore – Bernardo 69 kV line, submitted by SDG&E in the 2010-2011 request window with a proposed in-service date of 2015, to be needed and therefore the projects to reconductor the three lines are not needed.

Loss of Poway – Pomerado 69 kV line creates 5% voltage deviation at Poway 69 kV bus. This deviation is observed only in the 2020 study case, and will be further evaluated in future planning cycles.

Sweetwater 69 kV Area

This area experiences four overloads for the loss of a single element. The overloaded lines are –

- South Bay – Sweetwater 69 kV line;
- South Bay – Montgomery Tap 69 kV line;
- Sweetwater – Montgomery Tap 69 kV; and
- Sweetwater – Sweetwater Tap 69 kV line.

South Bay – Sweetwater 69 kV line becomes overloaded for the loss of Montgomery – Sweetwater – South Bay 69 kV line starting in 2013. The rest of the overloads are caused by Silvergate – South Bay 230 kV line contingency. The ISO has determined that the project to reconductor *South Bay – Sweetwater 69 kV Line,* submitted by SDG&E in the 2010-2011 request window with proposed in-service date of 2013 is needed to mitigate reliability concerns. The remaining three overloads will be mitigated by two re-rate/terminal equipment upgrade projects submitted by SDG&E – *TL642A, South Bay – Montgomery Tap – Terminal Equipment* and *TL603B, Sweetwater – Sweetwater Tap – Terminal Equipment.* Both projects were submitted as information only projects and the ISO concurs with these mitigations.

Sycamore 69 kV Area

Sycamore – Scripps 69 kV line may experience overload in 2015 due to the loss of Otay Mesa – South Bay 230 kV line under high import scenario where the import assumption is even higher than the one in 33% renewable study. SDG&E submitted the *TL6916, Sycamore-Scripps Overload Mitigation Project*. This project proposed to build a new Sycamore Canyon – Miramar 69 kV line. The ISO recommends using Miramar peakers to mitigate this issue. The peakers can provide sufficient mitigation even beyond 2020; hence the project is not needed.

Another project was submitted, *Los Coches Substation 230 kV Expansion Project*, which in addition to improving system reliability would solve this overload problem. This project seems to mitigate the overload on Sycamore – Scripps 69 kV line, but the ISO recommends using Miramar peakers for that purpose. Thus this project is not needed as a reliability project. In addition, this project claims to serve the cause of renewable integration by providing additional outlet for generation at Imperial Valley. These advantages were considered in developing the mitigation plan for the 33% renewable study which is part of this transmission plan. These factors are properly considered in the ISO's assessment of needed policy-driven transmission projects.

SDG&E also proposed the *TL633, Bernardo – Rancho Carmel 69 kV: Reconductor Project*. This line reaches its capacity in 2020, but does not show a severe overload. Area peakers are sufficient to mitigate this concern for the study horizon. The need for this upgrade will be further evaluated in a future planning cycle.

San Diego Area Reactive Support

SDG&E proposed the *Install Synchronous Condensers at Mission, Penasquitos and Talega 230 kV Substations Project* to address and anticipated need for reactive sources and sinks in the area. The reliability assessment performed by the ISO did not identify any issues that can be mitigated by these upgrades. These upgrades can solve an expected issue of reactive source-sink availability if and when Encina plant is retired. But there is a possibility of Encina re-powering and at this point of time the ISO has identified this project as a potential solution for voltage stability. The need will be evaluated in future planning cycles as the generation retirement issue becomes clearer.

Another reactive support project, *Add one 138 kV 43 MVAR Capacitor at Telegraph Canyon Substation Project* was submitted by SDG&E. A fast-track approval was requested for this project. Based on verification of SDG&E area load power factor and verification of reactive capability of Encina unit 5, the ISO concluded that the capacitor was not required at this point. The need for this reactive support will be evaluated in future planning cycles.

Emergency Conditions – Loss of a Two or More BES Elements (TPL 003)

In addition to the transmission facilities that would overload for Category B contingencies, there were additional transmission lines that may overload for Category C contingencies.

For these overloads that are listed in Appendix A, the NERC reliability standards allow for controlled load curtailment. The ISO recommends developing operating procedures or SPSs to drop load or generation for these contingencies.

The list of overloaded facilities and proposed mitigations is shown in Appendix A.

Mission-Old Town Area

SDG&E proposed the *Reconfigure TL23013 and TL23028 Project* for this area. The scope of this project includes converting TL23013 from a bundled line into two single conductor 230 kV lines and reconfiguration between Silvergate, Penasquitos, Old Town and Mission 230 kV substations. This project would eliminate the need to shed load under an extreme contingency which includes the loss of Otay Mesa power plant and TL50001 and TL23013 which is a (G-1/N-1 + N-1) contingency. After the *Sunrise Powerlink Project* comes into service, this scenario will be even more unlikely as it will have to be a (G-1/N-2 + N-1) contingency, hence this project is not needed.

Orange County Area

The southern Orange County area in SDG&E's service territory demonstrates multiple Category C-driven issues by 2020. More than 40 combinations of contingencies can result in load shed in the southern Orange County area. Some of these problems are existing ones and there are SPSs to address these issues. Detailed contingency analysis results are presented in Appendix A. There are more than 40 contingencies that result in overloads in 2020 and the number is more than 70 beyond 2025. The ISO standards do not recommend using SPS that looks at more than six contingencies causing more than four elements to get overloaded. This highlights the need for a reliability upgrade in the area. Southern Orange County is fed by a single 230 kV source at Talega. Failure of certain components in this area under maintenance conditions can result in loss of entire South Orange County load which is expected to be about 523 MW by 2020. There are 16 combinations of credible contingencies just at Talega substation which result in loss of partial or complete Orange County load under maintenance condition. Historical planned outage data reveals that 'load at risk' notifications have been part of several planned outages in recent past. These notifications are issued when more than 100 MW of load is at risk during planned outage conditions. In 2009-2010, 'load at risk' notifications were issued on 50 days. This indicates that any maintenance work at Talega substation or at several other 138kV facilities frequently results in an increased risk of loss of load on the southern Orange County system. Loss of this load is also an existing concern due to the topology in this area. The proposed solution and alternatives have proposed in-service date of June 2015.

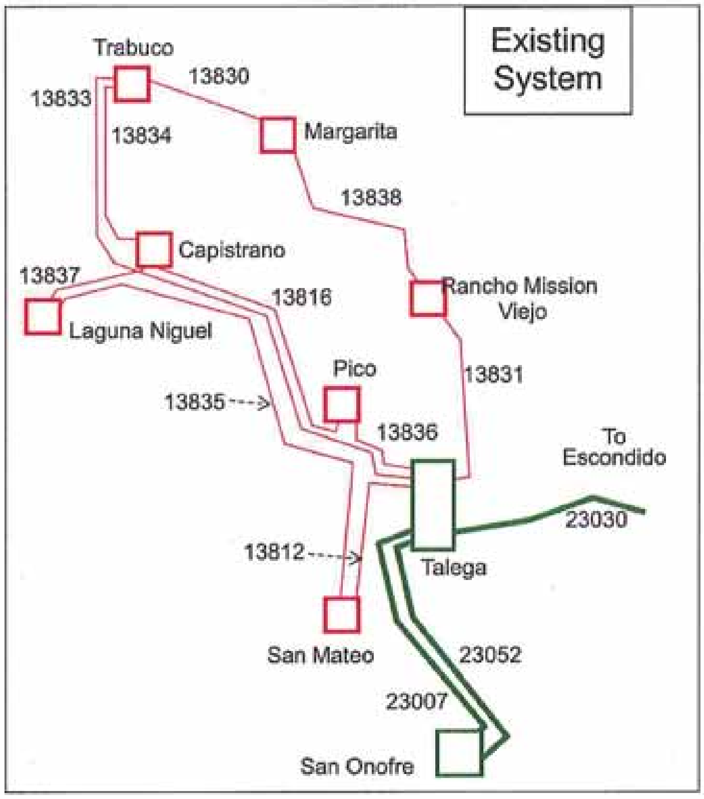


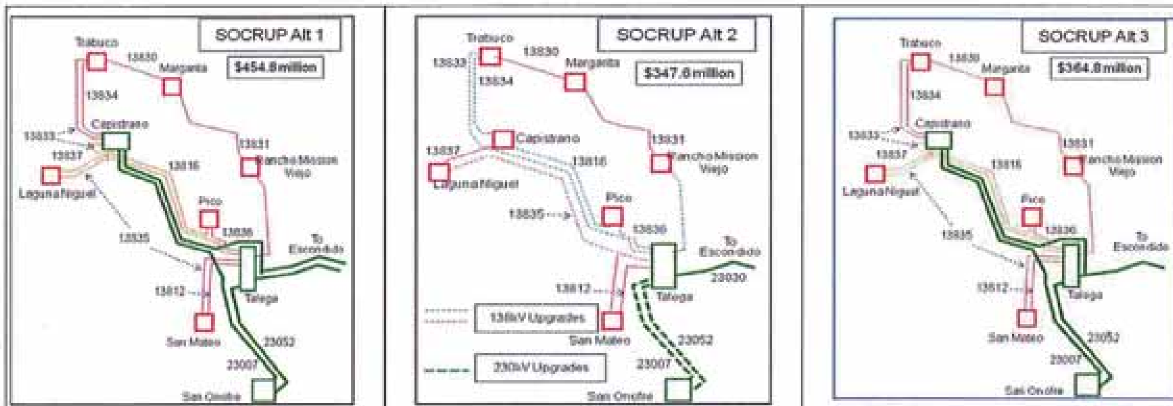
Figure 2.19-5: Existing Southern Orange County System

SDG&E submitted the *Modified – South Orange County Reliability Upgrade Project* to build new 230 kV lines and bring an additional source into southern Orange County in the 2008 request window and the ISO has been evaluating this project over several transmission planning cycles. The *Southern Orange County Reliability Upgrade Project (SOCRUP)* studies performed by SDG&E and the ISO provide substantial evidence that reliability need for upgrades exists in this area and the most effective method for achieving this is to add another source into this system. Most of the reliability concerns stem from the fact that only one 230 kV source feeds entire southern Orange County load. While it is important to develop a plan and ensure that the reliability concerns are addressed appropriately, it is also important to recognize that the upgrades should be optimal and cost effective. The southern Orange County area is susceptible to multiple Category C overloads by 2020, each requiring load shedding in this area. Under maintenance conditions, these load shed requirements are greater than 100 MW and can be as high as the entire southern Orange County load. Given these issues, the ISO performed an in-depth southern Orange County area transmission assessment to identify the necessary transmission upgrades in order to serve the area load reliably. After determining that alternative 2, the lowest cost alternative, required $347.6 million in investment, the ISO wanted to ensure that this investment would be a cost effective long-term plan. Therefore, all of the alternatives were designed to last beyond 2025 and compared on that basis. The purpose of this analysis was to identify the minimum upgrades needed during this timeframe to address NERC compliance and then to explore possibilities for alleviating concerns caused by a single source supplying the entire southern Orange County load. In addition to mitigating Category C issues, upgrades were identified to resolve issues faced under maintenance scenarios which can put significant load at risk. This effort led to creation of alternatives described below.

The project submitted by SDG&E was referred to as *SOCRUP Alternative 1*. The ISO worked with SDG&E to come up with two additional alternatives (*SOCRUP Alternative 2 and Alternative 3*). *SOCRUP Alternative 2* aims at upgrading 138kV system to solve potential overload issues, but it does not solve the problems created due to lack of a second source into this area. *SOCRUP Alternative 3* is a trimmed down version of alternative 1 (proposed by SDG&E) and provides similar reliability benefits as Alternative 1 while saving considerable amount of money.

Here is a brief summary of scope of each of these alternatives:

1. **SOCRUP Alternative 1:** Rebuild Capistrano 230 kV substation, build a new SONGS – Capistrano 230 kV line using existing right-of-way, and build a new Escondido to Capistrano 230 kV line using existing right-of-way. Estimated cost for this alternative is $454.8 million.
2. **SOCRUP Alternative 2:** Rebuild Capistrano 138kV substation (aging infrastructure maintenance project), reconductor 138kV lines – Talega – Pico, Talega – Laguna Niguel, Talega – Trabuco, Capistrano – Trabuco, Talega – Rancho Mission Viejo, and upgrade SONGS – Talega 230 kV lines. Upgrade two 230/138 kV transformer banks at Talega. Estimated cost for this alternative is $347.6 million.
3. **SOCRUP Alternative 3:** Rebuild Capistrano 230 kV substation, build a new SONGS – Capistrano 230 kV line using existing right-of-way, and tap off a 230 kV line to Capistrano from existing Escondido – Talega 230 kV line. Estimated cost for this alternative is $364.8 million.



-Reliable but most expensive
-Cheaper alternative provides similar reliability benefits

-No additional source into Orange County
-Only marginally cheaper than Alt 3 which brings another source into Orange County
- Mitigates cat-C overloads but Orange County load will still be at risk under planned outage conditions
-Does not mitigate issues with Talega substation configuration

-Provides similar reliability benefits as Alt-1, yet considerably cheaper
-Marginally more expensive than the cheapest alternative
-Additional source into Orange County
-Provides infrastructure for a possible future interconnection with SCE in Orange County.
-Flexibility to easily expand this into Alt-1 if required in future.

Figure 2.19-6: Southern Orange County Reliability Upgrade Project (Alternatives 1, 2 and 3)

Power flow study results of the peak load scenarios identified numerous facility loadings that exceeded their rated capabilities under Category C contingencies beyond 2015. All three alternatives considered here can mitigate the loading issues for Category C contingencies. In order to determine the most effective alternative, aspects beyond just the NERC compliance were taken into consideration. Historical data for bus outages at Talega and planned outages that put load at risk was accumulated and examined. It was quite evident that the lack of second source into southern Orange County puts more load at risk than the Category C issues noticed in the reliability assessment of the system. Hence, in order to improve the overall reliability of this system, it is important to bring another source into this area. The project submitted by SDG&E (Alternative 1) aims to achieve this, but Alternative 3 achieves similar reliability performance at a considerably lower cost. Alternative 2 mitigates the Category C issues through 2021, but fails to deliver another source into this area and hence fails to address the risk of load shedding due to contingencies at Talega. Alternative 3 provides another source into southern Orange County system at very little extra cost compared to Alternative 2. It also offers a potential for future upgrades in case of further load growth. After a comprehensive analysis, the ISO staff concluded that *SOCRUP Alternative 3* as the most effective, feasible solution to meet the reliability needs of southern Orange County area. Therefore, the ISO has found that the *SOCRUP Alternative 3* project is needed to address the reliability concerns in the southern Orange County area.

Other Projects

There were two projects submitted in the Imperial Valley region with a wide geographical scope:

The *North Gila - IV #2 Double Circuit Project* was submitted by Southwest Transmission Partners and on behalf of Energy Capital Partners II and its affiliates. The proposed project to build a second North Gila to Imperial Valley 500 kV double circuit line would increase the West of River transfer capability by up to 3000 MW. The project also claims to deliver significant amount of renewable resources bi-directional between Arizona and California. The reliability need for this project was not identified in the ISO's reliability assessment studies; hence the project is not needed as a reliability project.

The *IV Renewable Transmission Project (Reliability)* was submitted by Citizens Energy Corporation. This project aims at collecting and delivering renewable generation located in Imprial Valley to concentrated retail energy markets principally in southern California. Due to the interconnection to Arizona and Nevada, this project also claims to deliver renewable energy from and to those areas. The reliability need for this project was not identified in ISO's reliability assessment studies; hence the project is not needed as a reliability project.

2.19. 5 Key Conclusions

The ISO initially proposed a total of 10 upgrades (see Appendix A) to address identified reliability concerns.

In response to the ISO study results and proposed solutions:

- 28 reliability project submissions were received through the 2010 request window. Out of the 28 reliability projects, several projects were alternatives for solving the same problems.

The following nine projects are determined to be needed by the ISO:

- *TL644, South Bay-Sweetwater: Reconductor*. Proposed in-service date given by SDG&E is 2013;
- *New Sycamore – Bernardo 69 kV Line*: Proposed in-service date is June, 2015;
- *TL626 Santa Ysabel – Descanso mitigation*: Proposed in-service date is June, 2013;
- *Reconductor TL663, Mission-Kearny*: Proposed in-service date is June, 2015;
- *Reconductor TL670, Mission-Clairemont*: Proposed in-service date is June, 2015;
- *Reconductor TL676, Mission-Mesa Heights*: Proposed in-service date is June, 2015;
- *TL694A San Luis Rey-Morrow Hills Tap*: Reliability: Proposed in-service date for this project is June, 2012;
- *Upgrade Los Coches 138/69 kV Bank 50*: Proposed in-service date is June, 2013; and.

- *South Orange County Reliability Upgrade Project (SOCRUP) Alternative 3*[24]: Proposed in-service date is June, 2015.

The following 11 projects submitted in the request window are determined not to be needed:

- *TL648, Poway – Rancho Carmel*: 69 kV Reconductor: Proposed in-service date is June, 2015;.
- *TL6915 & TL6924 Sycamore-Pomerado #1 & #2*: Reconductors: Proposed in-service date is June, 2015;
- *TL682 Warner-Rincon*: Reconductor: Proposed in-service date is June, 2012;
- *TL693 San Luis Rey-Melrose: Reconductor*: Proposed in-service date is June, 2015;
- *TL694A San Luis Rey-Morrow Hills Tap*: Reliability: Proposed in-service date is June, 2012;
- *TL680B – Melrose-Melrose Tap Reconductor;* Proposed in-service date is June, 2013;
- *TL6916, Sycamore-Scripps Overload Mitigation (a new Sycamore – Miramar 69 kV Line)*: Proposed in-service date is June, 2015;
- *Reconfigure TL23013 and TL23028*: Proposed in-service date is June, 2011;
- *Barrett Interim Solution*: Proposed in-service date is October, 2012;
- *North Gila - IV #2 Double Circuit Project:*. Proposed in-service date is May, 2015; and
- *Imperial Valley Renewable Transmission Project (Reliability Project)*: Proposed in-service date is September, 2015.

The following eight projects will be evaluated in future planning cycles –

- *Reconductor TL631, El Cajon-Los Coches*: Proposed in-service date is June, 2013;
- *TL633, Bernardo – Rancho Carmel 69 kV*: Reconductor: Proposed in-service date is June, 2012;
- *Los Coches Substation 230 kV Expansion*: Proposed in-service date is June, 2015;
- *TL6912 - Reconductor San Luis Rey-Pendleton*: Proposed in-service date is June, 2020;
- *Upgrade Mission 138/69 kV Transformer Banks 51 and 52*: Proposed in-service date is June, 2015;
- *TL13835B Laguna Niguel - Talega Tap Mitigation*: Proposed in-service date is June, 2020;
- *Install synchronous condensers at Mission, Penasquitos and Talega 230 kV Substations*: Proposed in-service dates for these synchronous condensers are June 2013, June 2016 and June 2019; and
- *Add one 138 kV 43 MVAR Capacitor at Telegraph Canyon Substation*: Proposed in-service date is April, 2011.

During this year's reliability assessment, all the Category B problems observed were addressed by projects submitted through request window. After considering all the alternatives the ISO has determined 9 projects are needed. Out of the 11 projects found not to be needed during this planning cycle, several projects are alternatives to the approved ones. The remaining projects which are not deemed necessary at this point will

[24] 'South Orange County Reliability Upgrade Project (SOCRUP) Alternative 3' was formulated during evaluation of a project submitted by SDG&E – 'Modified - Southern Orange County Reliability Upgrade Project (M-SOCRUP)'. The ISO and SDG&E worked together to come up with SOCRUP Alternative 3 which has a reduced scope compared to M-SOCRUP. Refer to 'Orange County Area' write up under section 2.19.4 for further details.

be further evaluated during future planning cycles. The projects determined to be needed during this planning cycle will be included as planning assumptions for the next planning cycle.

Exhibit No. SDG-3

California Public Utilities Commission
The Certificate of Public Convenience and Necessity Application Process for Utility Construction Transmission Projects

A Step-By-Step Guide

OVERVIEW:

The California Public Utilities Commission's (CPUC) review of transmission line applications takes place under two concurrent and parallel processes:

(1) environmental review pursuant to the California Environmental Quality Act (CEQA), and

(2) review of project need and costs pursuant to Public Utilities Code sections 1001 et seq. and General Order (G.O.) 131-D.

The environmental review process is administered by CPUC staff, and invites broad public participation through scoping meeting(s) and written comment periods. The review of project need and costs is administered by an Administrative Law Judge (ALJ) and is subject to compliance with the CPUC's Rules of Practice and Procedure. Participation in the review of the project need and costs is limited to official parties. For this reason, we sometimes refer to this part of the proceeding as the "formal" part of the proceeding.

These two review processes converge at the conclusion of the environmental review when the CPUC staff submits its final environmental report into the formal proceeding. Depending upon the impacts of the proposed project, the final environmental document may be either an Environmental Impact Report (EIR), a Mitigated Negative Declaration (MND) or a Negative Declaration (ND). Based on the information generated during both the environmental review process and the formal process of determining need and costs, the CPUC may approve the utility's proposed project, an alternate project, or no project.

This step-by-step-guide describes how the CPUC reviews a transmission line application when it decides to prepare an environmental impact report.

Any person may participate in the environmental review of a proposed project. This participation can include attending a project scoping meeting and providing oral comment at all public meetings and providing written comments on the draft environmental documents as described in the table below. However, in order to participate in the formal part of the proceeding administered by an (ALJ), a person must become a "party" under Rule 1.4 of the CPUC's Rules of Practice and Procedure[1]. Any person not a party to the proceeding may also provide oral comment at public participation hearings held as part of the formal proceeding.

STEP-BY-STEP GUIDE:

Application Filed with the CPUC: The utility files an application for a Certificate of Public Convenience and Necessity (CPCN) for facilities 200 kilovolts (kV) and above or a Permit to Construct (PTC), for facilities between 50 kV to 200 kV. The application will include the utility's Proponent's Environmental Assessment (PEA) focusing on the proposed project's environmental impacts along with applicant proposed mitigation measures and alternatives to the project. The application identifies the utility's preferred project alternative; however, the CPUC may approve the proposed project, an alternative to the proposed project, or no project.

The filing of the Application triggers the start the two review processes.

SUMMARY OF REVIEW PROCESSES

ENVIRONMENTAL REVIEW	NEED/COST REVIEW
Completeness Review – CPUC staff review the filed application and the PEA, for completeness. Within 30 days of the filing date, staff either deem the application complete or notify the utility of any deficiencies. Once deficiencies are corrected, CPUC staff sends a letter to the applicant deeming the application complete. **Initial Study** - When it is not clear whether CEQA requires an EIR or a MND, an Initial Study is prepared to determine which is appropriate.	**Protests/Responses filed** – Pursuant to G. O. 131-D, §XII protests to the application are due within 30 days after the notice was mailed or published. **Prehearing conference (PHC)** – If it is preliminarily determined that an evidentiary hearing is needed, or if protests are filed, the Administrative Law Judge (ALJ) will conduct a PHC to identify the issues to be addressed in the proceeding, determine whether evidentiary hearings are needed, and to discuss the schedule for the proceeding

[1] Unless otherwise specified, all references to CPUC Rules are to the CPUC's Rules of Practice and Procedure available on the CPUC's website at: http://docs.cpuc.ca.gov/published/RULES_PRAC_PROC/70731.htm

[2] The public comment period may be longer if the document is a joint environmental document prepared under both CEQA and the National Environmental Policy Act (NEPA).

Public Workshops – CPUC transmission and environmental permitting staff may meet with the public to explain the CPUC and CEQA processes, the purpose of these processes, and how they are interrelated. This would normally occur before the Notice of Preparation is mailed out.

Notice of Preparation (NOP) and Comment on the NOP – If it is determined that an EIR is required, CPUC staff will issue a NOP to request agency and public comment on the scope and content of the EIR and to notice the time and location of scoping meetings for public participation.

Agency Consultations and Public Scoping Meetings – CPUC transmission and environmental permitting staff meet with other agencies and the public to get their input into the proposed project route and/or facility sites as well as any alternatives to the proposed project. In addition, input is sought on project issues, impacts, and mitigation measures for the project. Public scoping meetings are typically held within 30 days of the issuance of the NOP. Scoping comments are due 30 days after issuance of the NOP.

Draft EIR – CPUC staff issues the Draft EIR which assesses the environmental impacts of the proposed project and alternatives, identifies mitigation measures for each significant impact, and identifies the environmentally superior alternative. The public comment period on the Draft EIR is usually 45 days[2].

Public Meetings on Draft EIR - During

and other procedural matters.

Scoping Memo – After the PHC, the Assigned Commissioner issues a scoping memo determining the issues, schedule and other procedural matters for the proceeding.

Hearings and Briefs – Parties file written testimony, cross-examine witnesses at evidentiary hearings, file written briefs, and appeal any final decision.

Evidentiary hearings will generally be limited to matters other than the environmental issues addressed in the CEQA process and will be held no sooner than after the Draft EIR issues. If evidentiary hearings are set, the schedule will generally provide for prepared testimony to be filed by the parties, with the evidentiary hearings limited to cross-examination of witnesses sponsoring the written testimony.

Whether or not evidentiary hearings are set, the schedule will generally provide for the filing of **briefs** by the parties.

The ALJ may hold one or more **public participation hearing(s)** in the communities affected by the project to allow for comments from members of the public who are not parties in the proceeding. Transcripts from these hearings are available to the five Commissioners, and Commissioners may attend these public participation hearings.

the public comment period, public meetings are held to discuss the results of the Draft EIR and how to comment on the Draft EIR. **Comments on Draft EIR** – Interested persons may submit written comments on the Draft EIR within the specified public comment period. **Final EIR** – The Final EIR, which includes the Draft EIR and responses to the public's comments on the Draft EIR, is prepared and submitted into the formal record of the proceeding.	

Proposed and Alternate Decisions – Once the two review processes, as described above, have concluded, the ALJ prepares a proposed decision (PD) which includes information from the Final EIR regarding the proposed project, project alternatives, impacts, and mitigations. The assigned Commissioner may concurrently prepare and issue an alternate decision to the PD. Once the PD and any Assigned Commissioner alternate have been issued, other Commissioners may subsequently issue alternate decisions. All CPUC decisions, whether a PD or an alternate, must be based upon the evidentiary record, which includes the Final EIR and the testimony of the parties from the filed testimony and evidentiary hearings.

Comment on Proposed and Alternate Decisions – Most PDs and alternate decisions are subject to 30 days of public review and comment before the CPUC may vote on them. .

CPUC Vote – The CPUC votes on the PD and any alternate decision(s) at a public business meeting after the period for public review and comment has passed.

Recommended Resources

- **California Statutes** – available at www.leginfo.ca.gov/calaw.html
    - o Statutes related to Certificates of Public Convenience and Necessity (CPCN) - California Public Utilities Code Sections 1001-1005.5
    - o California Environmental Quality Act (CEQA) – California Public Resources Code Sections 21000, et seq. See also: http://ceres.ca.gov/ceqa/
    - o Permit Streamlining Act – California Government Code Sections 65920-65963.1
    - o CEQA Guidelines – California Code of Regulations, Title 14, Chapter 3

- **Recent CPUC Transmission Line decisions** - Specific CPUC decisions may be located by decision number on the CPUC's website at http://www.cpuc.ca.gov/static/documents/index.htm
    - o Jefferson-Martin, D. 04-08-046
    - o Valley-Rainbow, D. 02-12-066
    - o EMF issues, D. 06-01-042
    - o Renewable Portfolio Standard (RPS) need determination, D.04-06-010

- **CPUC General Order 131-D** – "Rules Relating to the Planning and Construction of Electric Generation, Transmission/Power/Distribution Line Facilities and Substations Located in California" – available at www.cpuc.ca.gov/PUBLISHED/Graphics/589.PDF

- **CPUC General Order 159-A** – "Rules Relating to the Construction of Commercial Mobile Radio Service Facilities in California" available at http://www.cpuc.ca.gov/Published/Graphics/611.pdf

- **CPUC CEQA requirements** – "Information and Criteria List" – available at www.cpuc.ca.gov/static/energy/environment/infocrit.htm

- **CPUC "Guide to Public Participation"** – available at www.cpuc.ca.gov/PUBLISHED/REPORT/46182.htm

- **CPUC Rules of Practice and Procedure** – available at www.cpuc.ca.gov/PUBLISHED/RULES_PRAC_PROC/46095.htm

- **CPUC Executive Director's Statement Establishing Transmission Project Review Streamlining Directives** – available at http://www.cpuc.ca.gov/static/energy/environment/index.htm

- **Questions?** – Contact the CPUC's Public Advisor's Office at public.advisor@cpuc.ca.gov or (415) 703-2074 or toll free at (866) 849-8390; TTY (415) 703-5282 or TTY toll free at (866) 836-7825.

Recommended Resources

- **California Statutes** – available at www.leginfo.ca.gov/calaw.html

    - o Statutes related to Certificates of Public Convenience and Necessity (CPCN) - California Public Utilities Code Sections 1001-1005.5
    - o California Environmental Quality Act (CEQA) – California Public Resources Code Sections 21000, et seq. See also: http://ceres.ca.gov/ceqa/
    - o Permit Streamlining Act – California Government Code Sections 65920-65963.1
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Exhibit No. SDG-4

A Sempra Energy utility®

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8330 Century Park Court
San Diego, CA 92123-1530

September 9, 2015

President Michael Picker
Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: SDG&E's South Orange County Reliability Enhancement Project, A. 12-05-020

Dear President Picker:

Safe and reliable electric service is at the heart of our business. As such, we are writing to request an effective and expeditious resolution to San Diego Gas & Electric Company's application for the South Orange County Reliability Enhancement (SOCRE) Project. SDG&E has been seeking to address reliability and resiliency challenges in southern Orange County since 2008. The SOCRE Project is intended to support reliable electric service to SDG&E's more than 120,000 customers (including approximately 300,000 residents) in southern Orange County.

SDG&E filed for Commission approval of the SOCRE project three years ago, following approval by the California Independent System Operator (CAISO) Board of Directors in 2011. Currently, our southern Orange County customers are served by a 138 kV system sourced from a single 230 kV to 138 kV substation. Because there is only one source, southern Orange County customers are at risk of prolonged outages or other disruptions should problems occur at this substation. In the case of physical attack, fire or other catastrophic events, such an outage could last days or weeks. In addition to economic impacts and inconvenience, such outages can impact public safety, such as health care, public schools, police and fire response, traffic signals, access to telecommunications, the supply of fresh water and treatment of wastewater. The SOCRE Project would mitigate these risks and improve resiliency by providing a second independent 230 kV source to southern Orange County at the proposed rebuilt Capistrano Substation, which is at the load center for the area.

After careful technical review and evaluation of several alternatives in its annual transmission planning process (in which CPUC representatives participate), the CAISO approved the SOCRE Project as the best project to address the identified reliability issues in its 2010-2011 Transmission Plan. The CAISO applied the Reliability Standards adopted by the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy

Regulatory Commission pursuant to Section 215 of the Federal Power Act, as well as its own Planning Standards adopted pursuant to California law and its FERC-approved tariff. SDG&E is required by federal law to comply with the mandatory NERC reliability standards and by contract to comply with the CAISO Planning Standards. Without some project, SDG&E's existing southern Orange County system will not continue to meet the NERC-required performance level.

The SOCRE Project allows SDG&E to comply with the NERC Reliability Standards by ensuring that the system remains within applicable facility ratings following certain overlapping equipment outages. The SOCRE Project also allows SDG&E to comply with NERC Reliability Standards during necessary maintenance events. In addition to meeting these mandatory requirements, the SOCRE Project also mitigates numerous other contingencies under which SDG&E would have to interrupt electric service to its customers, and mitigates the risk of southern Orange County being reliant on power from a single substation. The SOCRE Project is designed to maintain the system's compliance with FERC's requirements, and to avoid the unnecessary loss of electric service to customers. This is a priority for SDG&E and we hope for the Commission.

A Commission decision on this Project should be a priority because it has been pending for too long. SDG&E began working with the Commission's CEQA Staff in October 2011 and filed its application seeking a Certificate of Public Convenience and Necessity (CPCN) for the SOCRE Project on May 18, 2012. The application was deemed complete in January 2013, and the CEQA scoping meetings and comment period were complete by February 2013. CEQA staff just issued a Recirculated Draft Environmental Impact Report ("Recirculated DEIR") and hearings will be reset for this November. We will not rehash the anomalies in the CEQA process that have contributed to the long delay, but simply note that environmental review of the Project has been halting and unpredictable. This kind of delay should not happen. As Governor Brown said in his 2013 State of the State address, "We also need to rethink and streamline our regulatory procedures, particularly the California Environmental Quality Act. Our approach needs to be based more on consistent standards that provide greater certainty and cut needless delays."

We want to note our concern that the Recirculated DEIR does not, and CEQA staff may not, be fully informing the Commission about the real life impacts of the identified alternatives to the SOCRE Project. The Recirculated DEIR includes several alternatives that propose interconnecting SDG&E's 138 kV system with Southern California Edison's (SCE) 220 kV system. SDG&E and CAISO already have informed CEQA staff that such an interconnection would have significant electrical import/export impacts on both the SDG&E and SCE systems. It will take years for SCE, CAISO and WECC to study these impacts, and determine and approve any necessary solutions, and the solutions will have to be in place before any interconnection would be permitted under SCE's FERC-approved tariff. The Recirculated DEIR does not mention the required interconnection process or the time to complete it, much less consider the environmental impacts and ratepayer costs of mitigating the impacts caused by such interconnection—none of which are caused by the SOCRE Project.

In addition, the Recirculated DEIR understates the reasonably expected environmental impacts of most of its alternatives to the SOCRE Project by assuming that Capistrano Substation would not be rebuilt if the SOCRE Project does not proceed. SDG&E repeatedly has informed CEQA staff that the Capistrano Substation is past its useful life, must be rebuilt to provide reliable electric service, and that, if the SOCRE Project is not approved, it will be rebuilt as a 138/12 kV substation. Despite attributing much of the air quality and traffic impacts to the rebuilding of Capistrano Substation as a 230/138/12 kV substation under the SOCRE Project, the Recirculated DEIR simply asserts that, if an alternative is chosen, all environmental impacts of rebuilding Capistrano Substation as a 138/12 kV substation will be avoided. This is not factually accurate, and results in the Recirculated DEIR's significant impact analysis being inaccurate. These omissions must be corrected in the Final EIR.

As you know, SDG&E has other applications currently pending before the Commission including critical fire safety projects, transmission lines that will ease congestion on the grid and save customers money, and substations to support major public facilities. We hope that this important reliability project will be a priority for the Commission without delaying other pending proceedings.

SDG&E is grateful that the Assigned Administrative Law Judge notified parties that hearings must be scheduled for November 9, 2015 or sooner, and that the process now appears to be moving forward. For the reasons noted above, I hope you will help ensure that the hearing dates remain on track so that the Commission can issue a final decision on the SOCRE Project in the first quarter of 2016. I also hope that you will look into the issues noted above to ensure that the Commission approves an effective and feasible project to address the identified reliability concerns.

Sincerely,

David L. Geier
Vice President, Electric Transmission and Systems Engineering

Dan Skopec
Vice President, Regulatory Affairs

cc: Steve Berberich, President and CEO, CAISO
Ed Randolph, Director, Energy Division, CPUC

Exhibit No. SDG-5

Table 3-19 (cont.): Anticipated Permit, Approval, and Consultation Requirements

Permit/Approval/Consultation	Agency	Jurisdiction/Purpose
Local Agencies		
Demolition Permit	City of San Juan Capistrano (ministerial)	Demolition of the existing abandoned utility structure.
Grading Permit	City of San Juan Capistrano (ministerial)	On-site grading activities at the Capistrano Substation.
Traffic Control Plan	County of Orange San Juan Capistrano and San Clemente	Construction within, under or over city or county road ROW.
Right of Way Encroachment	Southern California Regional Rail Authority	Construction within and under (jack-and-bore) railway ROW.
Building (Substation Perimeter Wall) Permit	City of San Juan Capistrano (ministerial)	Substation perimeter wall construction.
Street Improvements	City of San Juan Capistrano (ministerial)	Sidewalk and curb improvements.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served an electronic copy of the foregoing document upon the following:

Arocles Aguilar **(*via Overnight Mail*)**
General Counsel
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Roger Collanton **(*via Overnight Mail*)**
General Counsel
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630

Dated at San Diego, California, this 23rd day of September, 2015.

/s/ Tamara Grabowski
Tamara Grabowski
Legal Administrative Associate
8330 Century Park Court
San Diego, California 92123
(858) 654-1827