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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In The Matter of the Application of San Diego Gas and Electric Company (U 902 E) for a Certificate of Public Convenience and Necessity for the South Orange County Reliability Enhancement Project.	Application 12-05-020 (Filed May 18, 2012)

OPENING BRIEF
OF THE OFFICE OF RATEPAYER ADVOCATES

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SUMMARY OF RECOMMENDATIONS

1) The Proposed Project should be denied.

2) If the Commission selects an alternative, the Trabuco Alternative, as proposed by the Office of Ratepayer Advocates should be adopted.

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I. INTRODUCTION

San Diego Gas & Electric Company ("SDG&E") asserts that its Proposed Project should be approved and that the Trabuco Alternative would be infeasible. Under its costly Proposed Project, SDG&E would, among other things, overhaul and upgrade the Capistrano Substation from 138 kilovolts ("kV") to 230 kV, and construct approximately 7.5 miles of double circuit transmission lines to interconnect the upgraded Capistrano Substation to both the Talega Substation and the San Onofre Substation.

The Proposed Project is not needed. Load is decreasing in the South Orange County area ("SOC area"). Further, SDG&E's testimony regarding outages and the applicability and effect of North American Electric Reliability Corporation ("NERC") standards, is inconsistent and often erroneous. SDG&E's analysis is premised on extreme scenarios. In addition, SDG&E has not established that it cannot fix the Talega substation, within the Talega substation footprint, and spare ratepayers the costs of this expensive workaround.

The Trabuco Alternative, as proposed by the Office of Ratepayer Advocates ("ORA"), would upgrade the 138 kV Trabuco Substation to 230 kV, and loop in the upgraded Trabuco Substation to one of the San Onofre – Santiago transmission lines. The Trabuco Alternative is feasible, and provides more effective reliability enhancements to South Orange County customers at a lower cost, compared to SDG&E's Proposed

Project. If the Commission chooses ORA's proposed Trabuco Alternative, it should ensure that SDG&E, Southern California Edison Company ("SCE") and the California Independent System Operator ("CAISO") collaborate effectively to finalize project design and construction.

II. PROJECT NEED

No Project is currently needed to improve reliability in the SOC area.

A. South Orange County Load does not Justify any Project.

At hearings, critical information was disclosed by SDG&E that demonstrates that the Proposed Project is not needed. The peak load for the SOC area for 2015 was only 415 megawatts ("MW"), below SDG&E's load forecasts of 433.5 MW and 443.3 MW.[1] Despite the numerous corrections SDG&E made to its showing, it did not provide the 2015 peak load until the ALJ asked for the information at hearing.

> MR. RAUSHENBUSH: Your Honor, you had requested that SDG&E determine what the peak load so far for 2015 is, and Mr. Jontry has contracted folks back at SDG&E in San Diego and got that answer for you if you would like that now.
>
> ALJ FARRAR: Yes, Mr. Jontry.
>
> THE WITNESS: The peak load for 2015 for South Orange County was 415 megawatts.
>
> ALJ FARRAR: For the timeframe?
>
> THE WITNESS: For 2015. Peak load 2015.[2]

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[1] See Exhibit SDG&E 2.2, *SDG&E Corrected April 7, 2015 Supplemental Prepared Testimony of Scott Bockiewicz, Don Houston, John Jontry, Karl Iliev, Hal Mortier, Henry Nembach, Cory Smith, Michael Sullivan and Willie Thomas (includes September 10, 2015 corrections with certain September 10 changes removed per ALJ Ruling of November 9, 2015) (Public Version)* ("SDG&E 2.2") at 55:3-6, Table 2-1 and Table 2-2.

[2] RT at 205:8-19 (Vol. 2).

It should also be noted that the 2014 load forecast was similarly inflated. SDG&E projected 427.8 MW in its load forecast for 2014.[3] However, the actual peak load for the SOC area was 415.3 MW.[4] Putting aside the actual results for 2014 and 2015, with some methodology reservations, SDG&E also admits that its "non-coincident load forecast for South Orange County has decreased since 2011."[5] Taken together with historical loads, the actual peak load results for 2014 and 2015 run counter to SDG&E's theory that load is increasing in the SOC area.

In any event, ORA's witness Mr. Mee has already testified that:

> [T]he total power supply capacity of the four transformer banks at Talega Substation is around 1,100 MVA, which could provide as much as 1,100 MW of real power. Talega Substation has more than double the power supply capacity to serve the SOC area. Even if two of the old banks (Bank #60 with 162 MVA and Bank #62 with 150 MVA) at the Talega Substation are removed, the substation would still have a power supply capacity of 784 MVA (Bank #61 with 392 MVA and Bank #63 with 392 MVA) to serve the SOC area load.[6]

The fact that SDG&E's forecasts were significantly higher than actual loads casts doubt into the bulk of the power flows and other derivative analyses that SDG&E conducted to justify the Proposed Project.

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[3] See, e.g., SDG&E 2.2 at 55:6, Table 2-2.

[4] Exhibit Frontlines 413, *Excerpt from SDGE Response to Energy Division Data Request #8*.

[5] Exhibit SDG&E 1.3, *SDG&E Corrected Prepared Testimony Of John Jontry, Karl Iliev, And Cory Smith, January 15, 2015 (includes April 7, 2015 corrections and September 10, 2015 corrections with certain September 10 changes removed per ALJ Ruling of November 9, 2015)* ("SDG&E 1.3") at 37:2-3.

[6] Exhibit ORA 200, *CORRECTED PREPARED TESTIMONY OF CHARLES MEE ON SOUTH ORANGE COUNTY RELIABILITY ENHANCEMENT PROJECT (SOCREP)*, ("ORA 200") at 8:20 – 9:4.

B. SDG&E's Testimony Regarding Outages Does not Justify the Project.

SDG&E's testimony regarding outages is similarly unpersuasive. In an early data request, ORA had asked SDG&E the following: "Please provide detailed information on any uncontrolled and controlled outages SDG&E experienced within the last five years."[7] SDG&E responded:

> With the exception of the September 8, 2011 Arizona-Southern California Outage, there have been no uncontrolled or controlled outages of customer load in South Orange County within the last five years that can be attributed to the transmission system. The September 8th event is unrelated to the reliability issues described in the response to question 1.[8]

There should be no dispute that the September 8, 2011 outage, which had a system level cause, is not a justification for the Proposed Project. At hearings, Mr. Jontry essentially confirmed that SDG&E does not rely on the September 8, 2011 outage to justify the Proposed Project.[9]

Despite the paucity of actual outages, in its prepared testimony, SDG&E paints a dire picture regarding outage risks that it believes would be mitigated by the Proposed Project. In particular, SDG&E points to a July 18, 2013 outage in support of its perception of risk:

> The Talega Substation 138 kV bus supplies power to the 138 kV transmission network, which supplies the distribution substations. If a failure occurs that requires the Talega Substation 230 kV or 138 kV buses to be removed from service, power flow to South Orange County would be interrupted and SDG&E's South Orange County customers would lose electric service.

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[7] Exhibit ORA 205, *SDG&E 05/31/13 Response, A. 12-05-020 South Orange County Reliability Enhancement Project CPCN, DRA Data Request 8, Dated May 16, 2013* ("ORA 205"), at 1.

[8] ORA 205, at 1.

[9] RT at 84:12-26 (Vol. 1); 233:5-9 (Vol. 2); 251:12-22 (Vol. 2).

> This scenario actually occurred on July 18, 2013, resulting in all SDG&E customers in South Orange County losing electric service for a period of several hours. Fortunately, this event occurred in the early morning hours and there was little direct impact; however, had the event occurred during a busy working day, the economic and social impact would have been much more significant.[10]

ORA probed deeper into the issues raised by the July 18, 2013 outage and learned that it has nothing to do with the justifications for the Proposed Project. Pointing to SDG&E's own internal investigation report into the outage, ORA questioned Mr. Jontry regarding the conclusions:

> Q. Do you agree that one of the causes of this outage was miscommunication?
>
> A. The report states "communication equipment at San Mateo Substation failed to send a signal to relaying at Talega and Trabuco Substations," so within the context of that sentence, I would say that yes, miscommunication -- communications failure did lead to the event.
> …
> A. [Reading...]
> One this condition was detected on July 19, 2013, a design change was issued and implemented to correct for the operation of the relay.
> Q. Is it your understanding that SDG&E has resolved the cause of this outage?
> A. Yes.
> …
> A. [Reading...]
> The primary cause of this outage was mis-coordination of the 138 kV 5E, 5T, and 5W breaker failure relays with TL13833 relaying due to relay control system design.
> Q. Do you agree with this conclusion?
> A. Yes.
> …

[10] SDG&E 1.3, at 10:16 – 11:2.

> MR. MOLDAVSKY: Q. Okay. Do you agree with the conclusions of this report?
> A. Yes.[11]

Mr. Iliev, one of the contributors to the report, also agreed with the conclusions of the report.[12] On re-cross examination, Mr. Jontry clarified that the causes of the July 18, 2013 outage have no relation to the Proposed Project.

> Q. But you do recall your testimony yesterday about this outage being caused by miscommunication, correct?
>
> A. Yes.
>
> Q. This outage was also caused by incorrect protection sites, correct?
>
> A. Yes.
>
> Q. These causes have nothing to do with the SOCRE project, do they?
>
> A. No.[13]

Further, SDG&E concedes that the Proposed Project does not prevent all possible outages.[14] In sum, SDG&E's data on outages is not compelling, and does not justify the Proposed Project.

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[11] RT at 89:12-20, 90:14-21, 90:27 – 91:6, 92:2-4 (Vol. 1). See also Exhibit ORA 202, *Southern Orange County Outage Investigation Report, Incident Date: July 18, 2013*.

[12] RT at 926:4-25 (Vol. 7).

[13] RT at 254:6-15 (Vol. 2).

[14] RT at 288:2-7 (Vol. 2).

C. The South Orange County Area is a Local Area Network, and No Project is Needed to Avoid Alleged NERC Violations.

1. The South Orange County Area is a Local Area Network.

There should be no dispute that the SOC area is a local area network. ORA asked this question directly to SDG&E's witness Mr. Jontry on the first day of hearings:

> Q. Mr. Jontry, if you can direct your attention to what's been marked as SDG&E-1, Chapter 2, Section 2. …
>
> Q. I believe it starts at line 7. It's a section entitled "SDG&E's Existing South Orange County Transmission System."
>
> A. Yes, I see it. …
>
> Q. Okay. Directing your attention to page 9, line 1 and 2, could you read that sentence on to the record, and it starts with "This local area network."
>
> A. "This local area network is operated by the California Independent System Operator," parenthetically, "CAISO."
>
> Q. Okay. And is the local area network that you're referring to in that sentence the South Orange County Transmission System?
>
> A. Yes.[15]

By this testimony, SDG&E confirmed that the South Orange County Transmission System is a local area network. However, under cross by Frontlines, Mr. Jontry appeared to backtrack on this basic proposition:

> Q. Is the South Orange County load a local network?
> A. It is -- no, because it is not radially connected. It is connected through four transformers at Talega and include the buses.[16]

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[15] RT at 71:26-28, 72:7-11, 72:18-28 – 73:1 (Vol. 1).

[16] RT at 147:22-27 (Vol. 1).

Putting aside the tenuous basis upon which Mr. Jontry appeared to "re-categorize" the system, ORA notes that despite all of the modifications that have been made to SDG&E's testimony in this proceeding, SDG&E failed to modify its initial testimony on whether the South Orange County Transmission System is a local area network:

> **Section 2. SDG&E's Existing South Orange County Transmission System (Witness: John Jontry)**
> South Orange County's electric load is supplied by seven SDG&E 138/12 kilovolt (kV) distribution substations (Capistrano, Laguna Niguel, Margarita, Pico, San Mateo, Rancho Mission Viejo, and Trabuco). Each of these substations is fed from a local 138 kV network; the local network is in turn supplied from Talega Substation, which provides the sole 230/138 kV connection to the Southern California bulk power network. ***This local area network*** is operated by the California Independent System Operator (CAISO). The substation interconnection diagram shown in Figure 2-2, South Orange County 138 kV Substation Interconnection Diagram, illustrates how the distribution substations within the South Orange County service area are connected to each other and to Talega Substation.[17]

Mr. Mee's testimony also confirms that the South Orange County Transmission System is a local area network.[18] SDG&E's characterization that its "South Orange County 138 kV transmission system ***is part of*** the NERC-defined 'Bulk Electric System[,]'"[19] is inapposite.

[17] SDG&E 1.3, at 8:7 - 9:5 (emphasis added).

[18] ORA 200, at 1:7-8.

[19] Exhibit SDG&E 3.2, *SDG&E's Corrected June 24, 2015 Rebuttal Testimony of John Jontry, Karl Iliev, Cory Smith, and Willie Thomas (includes September 10, 2015 corrections with certain September 10 changes removed per ALJ Ruling of November 9, 2015) (Public version)* ("SDG&E 3.2"), at 4:14-16.

2. Footnote b is an Exception in the NERC Standards.

ORA has established that Footnote b is an exception in certain identified NERC standards.[20] While the applicability of this footnote has been disputed heavily in this proceeding, SDG&E has not supported its "no exception" perspective. The footnote is included in the standards with good reason, and cannot be simply read out of the standards in order to justify SDG&E's costly Proposed Project.

In his direct testimony, Mr. Mee cites to the Footnote b exception to the NERC Standards.[21] Footnote b states:

> Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.[22]

At the hearings, Mr. Jontry confirmed the inclusion of Footnote b across identified NERC standards:

> Q. Okay. Have you seen these documents before?
>
> [*Referring to ORA 210, Standard TPL-001-0.1; ORA 212, Standard TPL-002-0b; ORA 213, Standard TPL-003-0b; ORA 214, Standard TPL-004-0a.*]
>
> A. Yes.
>
> Q. Okay. To your knowledge, do all of these documents have what has been referred to in this proceeding as a footnote B?

---

[20] See Exhibit ORA 210, *Standard TPL-001-0.1* ("ORA 210"), at 5; Exhibit ORA 212, *Standard TPL-002-0b* ("ORA 212"), at 5; ORA 213, *Exhibit Standard TPL-003-0b* ("ORA 213"), at 5; Exhibit ORA 214, *Standard TPL-004-0a* ("ORA 214"), at 5.

[21] ORA 200, at 6, fn. 3.

[22] See, e.g., ORA 212, at 5.

> A. Yes. I believe Table 1 is reflected in all four of the detail standards, and that includes footnote B.[23]

Mr. Jontry also testified that: "[w]ith regard to this footnote, it is referring to nonconsequential load shed. In other words, it is referring to shedding of customer load that is not as a direct result of the faulted element."[24]

In an early data request response, SDG&E characterized Footnote b as an exception:

> … The Footnote b exception documented in Section 2.2.1.3 significantly reduces system reliability and is not allowed in the CAISO controlled transmission system. The CAISO has consistently approved capital projects which mitigate overloads caused by the loss of a single element. Footnote b was included in the PEA because it is part of the requirement and SDG&E sought to give all parties a clear understanding of the requirement, including the exception.[25]

At hearings, when asked about this SDG&E data request response. Mr. Jontry was less definitive:

> Q. Let's break it up a little bit. The word "exception" is referring to Footnote B, is it not?
>
> A. Yes.
>
> Q. Do you agree with the sentence that you just read onto the record regarding Footnote B as an exception?
>
> A. Yes.
>
> Q. Okay. Do you believe that Footnote B is an exception?
>
> A. I think it could be interpreted as such, however as I stated, we don't plan our system to that level and we're not permitted to by the ISO.

---

[23] RT at 74:9-17 (Vol. 1).

[24] RT at 76:14-18 (Vol. 1).

[25] ORA 205, at 3.

> Q. I guess if I could ask you to focus your response? Do you believe that Footnote B is an exception?
>
> A. I think it could be interpreted that way, yes.
>
> Q. Do you believe that Footnote B is not an exception?
>
> A. I think it speaks for itself. It doesn't use the term exception, but it could be applied that way.[26]

Later, on re-direct, SDG&E's counsel also identified Footnote b as an exception.[27] Fundamentally, if Footnote b "could be applied" to the NERC standards, then there is no reasonable basis to argue that it is not an exception. SDG&E's strained interpretation incorrectly reads Footnote b out of the standards.

3. SDG&E Testified Inconsistently Regarding the Consideration of Risk in NERC Standards, and Demonstrated an Inconsistent Understanding Regarding Risk in Transmission Planning.

a) SDG&E Testified Inconsistently Regarding the Consideration of Risk in NERC Standards.

SDG&E's apparent confusion regarding the applicability of the Footnote b exception is not surprising given its misunderstanding on the assessment of risk in NERC standards. In the second rebuttal testimony, Mr. Smith testified that: "ORA ignores the fact that NERC reliability standards are not based on probability."[28]

When cross-examined by ORA regarding this statement, Mr. Smith testified as follows:

> Q. Okay. Do you agree with that statement?

---

[26] RT at 80:8-81:3 (Vol. 1).

[27] RT at 232:14 (Vol. 2).

[28] SDG&E 5, *Second Rebuttal Testimony of John Jontry, Karl Iliev, Cory Smith, and Willie Thomas dated October 19, 2015 (Public Version)* ("SDG&E 5"), at 9:1.

A. I do.

Q Okay. Are you referring to all NERC Reliability Standards in making that statement?

MR. RAUSHENBUSH: Vague -- objection, vague.

ALJ FARRAR: It's broad. Can you narrow that down as to what NERC Standards he may be referring to?

MR. MOLDAVSKY: Fair enough.

Q. Identify each NERC Reliability Standard that you are referring to in this sentence.

A. The currently enforced TPLs, which would be TPL-002-0b, TPL-003-0b, and TPL-004-0, and the future TPL-001-4.

Q. Those NERC Reliability Standards that you just identified, are those all of the NERC Reliability Standards that you know of?

A. Those are the standards that I'm responsible for at SDG&E, and they are the only ones that I know of.

Q. To your knowledge, are there any NERC Standards that consider the probability of events?

MR. RAUSHENBUSH: Objection, vague. If he could narrow it to transmission planning standards, that would be somewhat helpful because --

ALJ FARRAR: Sounds fair to me.

MR. MOLDAVSKY: Q. So narrowed.

A. I'm not aware of any transmission planning standards that require probabilities to be taken into account when doing NERC assessments.

Q. Just to test that a little bit, are you aware of any NERC -- NERC Transmission Reliability Standards that consider the probability of events?

A. I am not.[29]

---

[29] RT at 274:15 – 276:1 (Vol. 2) (emphasis added).

On redirect, in contrast, Mr. Smith confirmed that a NERC standard considered risk:

> ***Q. Are there any NERC TPLs that direct the electric utilities to consider the risk and consequences of potential outage events?***
>
> ***A. Yes, there is.***
>
> Q. And can you describe which TPL that is?
>
> A. That's TPL-004-0, and that is considered a Category D event.[30]

On re-cross examination by ORA, Mr. Smith testified that risk was not considered.

> Q. Okay. You're also changing your testimony regarding the probability of events, are you not?
>
> A. I am not.
>
> Q. Okay. Well, do you recall testifying that the NERC standards do not consider the probability of events?
>
> A. That is correct.
>
> Q. And yet just now in response to questions posed by Mr. Raushenbush, you pointed to a NERC standard regarding risk; correct?
>
> A. That's correct.
>
> Q. Okay. Are risk and probability two different things to you?
>
> A. Risk is not defined by NERC. Risk is -- I believe they want us to identify what types of problems we may have in the system. And a risk could be a substation -- a single substation serving an entire load area.
>
> Q. So just to clarify, so you – as you sit here today, in your view, the NERC standards do not take into consideration probability; correct?

---

[30] RT at 1270:16-23 (Vol. 8) (emphasis added).

> A. I -- in my view. And I've never seen it articulated within the NERC standard about probability.
>
> Q. Do they or don't they?
>
> A. They do not.
>
> ***Q. Okay. Do they take into consideration risk?***
>
> ***A. As I said, risk is not a defined term by NERC.***
>
> ***ALJ FARRAR: So that's no?***
>
> ***THE WITNESS: It's no.***[31]

SDG&E's witness could not make up his mind as to whether risk was considered by the NERC standards. Indeed, SDG&E's interpretation of the NERC standards in its testimony cannot be relied on generally, given the condition of the record.

b) SDG&E Testified Inconsistently Regarding the Consideration of Risk in Transmission Planning.

On a related topic, there should be no doubt that risk, or the probability of events, is taken into consideration in transmission planning. Mr. Jontry confirmed that a 1-in-10 forecast is used regarding "[t]he probability that the maximum load in that forecast year will exceed that level."[32] However, Mr. Smith testified as follows:

> MR. MOLDAVSKY: Q. Well, do you know one way or the other whether SDG&E considers probability of events in transmission planning?
>
> A. We do a transmission planning assessment based on NERC reliability criteria. We do not consider probabilities when we eventually do those – those assessments. So as a practice -- as part of our process within SDG&E, we complete an assessment -- an analysis, which is an assessment. And

[31] RT at 1282:1 – 1283:7 (Vol. 8) (emphasis added).

[32] RT at 107:23-25 (Vol. 1).

> that analysis does not take into account the probability of an event occurring.
>
> Q. After the assessment --
>
> A. No --
>
> Q. Please let me finish the question. After the assessment, does SDG&E consider probabilities of events in transmission planning?
>
> A. No, it does not.[33]

Mr. Smith, later testified regarding SDG&E's 1-in-10 coincident load forecast that "it's about a 10 percent chance of occurring."[34] He confirmed that this refers to a probability.[35]

If SDG&E does not consider the actual probability of outages in its transmission planning, as Mr. Smith initially suggested, that would result in costly and unnecessary projects. Further, as exemplified by the Proposed Project, such projects would not be reasonably tailored to the actual risks in a given area.

4. No Project is Needed to Avoid Alleged NERC Violations.

a) SDG&E's Interpretation of NERC Standards is Erroneous.

Whether the Footnote b exception applies to the South Orange County Transmission System has been a point of contention throughout this proceeding. In opposing the application of the exception, SDG&E relies on obsolete interpretations from FERC Order 693 and FERC Order 762. SDG&E asserts the following:

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[33] RT at 277:6-26 (Vol. 2).

[34] RT at 279:19-20 (Vol. 2).

[35] RT at 279:21-23 (Vol. 2).

> In adopting the relevant NERC TPL reliability standards, FERC stated: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." Referring to "footnote b" of Table I, FERC stated it "allows for the interruption of firm load for consequential load loss," which FERC defined as "the load that is directly served by the elements that are removed from service as a result of the contingency." FERC further stated: "The Commission agrees that footnote (b) should permit manual adjustments including generation redispatch and transmission reconfiguration, but not load shedding, to return the system to a normal operating state within the time period permitted by the emergency or short term ratings." FERC repeated this admonition in later Order 762: "In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency."[36]

Subsequent to FERC Orders 693 and 762, the FERC adopted Order 786, on October 17, 2013. FERC Order 786 states:

> With regard to Reliability Standard TPL-002-0b, Table 1, footnote 'b,' ***which applies to planned non-consequential load loss***, the Commission directed NERC to clarify footnote 'b' regarding the planned non-consequential load loss for a single contingency event.[37]

FERC Order 786 also provides that the "[c]urrently-effective footnote 'b' deals with both consequential load loss and non-consequential load loss."[38] FERC Order 786 adopted Reliability Standard TPL-001-4, finding that "NERC adequately addressed the

[36] SDG&E 2.2 at 47:17 – 48:11 (internal citations omitted).

[37] FERC Order 786, 145 FERC ¶ 61,051, ¶ 61,363, 2013 FERC LEXIS 1765, at **7 (October 17, 2013) (emphasis added).

[38] FERC Order 786, ¶ 61,363, at **9, fn. 9.

directives and underlying reliability concerns of Order No. 693, Order No. 762, and the April 2012 NOPR."[39] Footnote 12 of NERC Standard TPL-001-4 states:

> An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.[40]

A subsequent FERC Order, referencing "TPL-002-0b, Table 1, footnote b and TPL-001-4, Table 1, Footnote 12" reiterated that "TPL-002-0b and TPL-001-4 … ***generally prohibit*** the loss of non-consequential load for certain N-1 contingencies."[41]

At hearings, Mr. Jontry was questioned by ORA as to why he did not refer to FERC Order 786 in his analysis.

> Q. Okay. Why didn't you refer to FERC Order 786?
>
> A. FERC Order 693 in this case addressed directly the relevant part of the TPL standards and specifically Footnote B. And it seemed to make it very clear on what the Commission's intent was for application of the TPL-002 standard in Footnote B with regards to that standard.

[39] FERC Order 786, ¶ 61,367, at **27.

[40] Exhibit ORA 211, *Standard TPL-001-4*, at 12, fn. 12.

[41] FERC Order 818, 2015 FERC LEXIS 1795, *49-50, fn. 80 (November 19, 2015) (emphasis added).

> Q. Were you familiar with FERC Order 786 at the time you wrote this testimony?
>
> A. Probably heard about it but was not particularly familiar with it.
>
> Q. Are you familiar with it now? And to clarify, are you familiar with FERC Order 786 now?
>
> A. No. Not especially right now, no.[42]

After providing Mr. Jontry with an excerpt of FERC Order 786 and Standard TPL-001-4, he conceded that non-consequential load loss was permitted under some circumstances.

> MR. MOLDAVSKY: Q. Is nonconsequential load loss permitted under Standard TPL-001-4?
>
> A. If it meets the conditions on standard typically as referred to here in Attachment 1 and is less than 75 megawatts, yes.
>
> Q. Under these circumstances nonconsequential load loss is permitted under the standard, correct?
>
> A. Yes.[43]

Mr. Smith referenced Category C contingencies in his related testimony.

> With respect to what NERC identifies as Category C contingencies, SDG&E must "demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I."[44]

[42] RT at 95:14 – 96:2 (Vol. 1).

[43] RT at 100:6-15 (Vol. 1).

[44] SDG&E 5, at 9:11-15 (internal citation omitted.)

Mr. Smith referenced Standard TPL-003-0b as the source of his quote.[45] Standard TPL-003-0b was marked as Exhibit ORA 213 at hearings.[46] Under cross-examination by ORA, Mr. Smith identified the portion of the standard that he did not quote.

> Q. … And you're quoting Requirement R1. That text is drawn from Requirement R1 in Attachment ORA-213. I want you to read the next sentence in Requirement R1 after your quotation, and if you could, please read it into the record.
>
> A. [Reading:]
>
> The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm non-recallable reserver (sic) power transfers may be necessary to meet this standard. …[47]

FERC precedent and the record of this proceeding support ORA's interpretation of the applicability of NERC standards. SDG&E's inconsistent, and selective testimony on this topic should be accorded no weight.

b) Mitigation is not Required for all Contingencies.

Mr. Mee testified that mitigation is not required for all contingencies:

> SDG&E describes some extreme events in its application, such as the potential for an outage at both the 230 kV and the 138 kV buses at the Talega Substation. These extreme events can be considered as Category D events under NERC standards. While these events are required to be studied, no mitigation action is required.[48]

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[45] SDG&E 5, at 9, fn. 21.

[46] RT at 73:21-24 (Vol. 1).

[47] RT at 283:12-24 (Vol. 2).

[48] ORA 200 at 6:11-14.

Mr. Smith did concede at hearings that under NERC TPL-004-0a, mitigation is not required for all contingencies.

> MR. MOLDAVSKY: Q. Is it true that TPL-004-0a does not require mitigation of all possible contingencies in transmission planning?
>
> MR. RAUSHENBUSH: Objection. Vague and overbroad.
>
> ALJ FARRAR: I'll allow it. Answer, please.
>
> THE WITNESS: The standard speaks for itself, but it is understood that we are only -- the only necessary part of the standard is that we understand the risks and consequences. They do not require us to mitigate every one -- every Category D listed in Table 1.[49]

Initially, Mr. Smith appeared to try to limit the CAISO interpretation on this rule to the San Francisco area. He eventually conceded that CAISO also interprets NERC TPL-004-0a as not requiring mitigation for all contingencies.

> This is from the CAISO planning standards effective April 1st, 2015. I'm on page 7. Looks like Chapter 7. Extreme event reliability standards, ***and this is related to the San Francisco Peninsula area.***
>
> The requirements of NERC TPL-001-4 require extreme event contingencies to be assessed. However, the standard does not require mitigation plans to be developed for these extreme events.
>
> …
>
> Q. And you agree that's not limited to San Francisco?
>
> A. It speaks for itself. I think that –
>
> …
>
> Q. Do you know one way or the other?

---

[49] RT at 290:12-26 (Vol. 2).

A. I do not.

…

Q. Is it your understanding that that sentence only refers to San Francisco?

A. No, it is not.[50]

Based on this record, there should be no doubt that, as ORA has maintained, mitigation is not required for all contingencies.

c) SDG&E's NERC Violation Analysis is Based on Extreme Events.

SDG&E's NERC violation analysis overstates the actual risks in the SOC area. As Mr. Mee explained in his testimony:

> SDG&E, in Table 4-1 and Table 4-2 of its Second Supplemental Testimony, listed a number of NERC "violations" and load shedding outcomes. However, these "violations" and outcomes are based on extreme scenarios with low probability of occurrence. For example, SDG&E assumed that Path 43 is stressed and that the dynamic reactive compensation is not operating continuously. Under these extreme scenarios, SDG&E conducted Category C studies (i.e. two line outages occurring at the same time). SDG&E did not discuss the frequency of the occurrence and the degree of "violation" and whether any operating procedures or Special Protection Schemes [citation to NERC TPL-003-0ob, R1] can bring back the overloaded sub-transmission lines, as listed in the far right column of Table 4-1, to be within the Applicable Ratings.[51]

Ultimately, no Project is needed to avoid SDG&E's alleged NERC violations.

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[50] RT at 292:18-28; 294:7-10,23-25; 296:11-13 (Vol. 2).

[51] Exhibit ORA 201, *CORRECTED REPLY TESTIMONY OF CHARLES MEE TO SAN DIEGO GAS & ELECTRIC'S SECOND SUPPLEMENTAL TESTIMONY ON THE SOUTH ORANGE COUNTY RELIABILITY ENHANCEMENT PROJECT* ("ORA 201"), at 5:11-22 (internal citation to footnote 6: NERC TPL-003-0b R1 states that "The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard.")

D. SDG&E is able to Mitigate Talega Substation Configuration Issues Without any Project.

Mr. Mee testified that the "Proposed Project will not address the engineering problems at Talega substation."[52] Indeed, the Proposed Project is largely a costly workaround in order for SDG&E to solve configuration issues at the Talega Substation.

Mr. Mee does acknowledge that "transformer banks #60 and #62 are too close to the control rooms" and thus "[i]f one of the transformers were to be on fire, the control room would not be accessible."[53] Further, "transformers #60 and #63 are directly interconnected to the 230 kV buses" and thus "[i]f any of them has a fault, the interconnected bus must be de-energized to isolate the fault transformer from the power system."[54] However, it is quite disproportionate to engage in all of the expansive work called for by the Proposed Project in order to cure the poorly designed Talega substation.

In his prepared testimony, Mr. Mee observed that "[i]t is normal practice to shutdown part of a substation to do maintenance, while allowing the other part to stay energized to supply power."[55] In order to fix the Talega substation problems, SDG&E could "remove transformer banks #60 and #62, and then reconfigure transformer bank #63 so that it can be fed from a more reliable breaker-and-a-half configuration."[56] Mr. Mee acknowledges that during this reconfiguration "there will be only one 230/138 kV transformer bank, with a capacity of 392 megavolt-ampere (MVA), supplying power to the SOC area."[57] However, in mitigation, "SDG&E could perform this reconfiguration exercise during off peak hours."[58]

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[52] ORA 200, at 8:5-6.

[53] ORA 200, at 6:17-18.

[54] ORA 200, at 6:19-21.

[55] ORA 200, at 7:7-8.

[56] ORA 200, at 7:17-18.

[57] ORA 200, at 7:19-21.

[58] ORA 200, at 7:22-23.

Fundamentally, SDG&E maintains that it is not feasible to solve the Talega substation configuration problems within the Talega footprint.[59] ORA disagrees with this premise, and tested SDG&E's assumptions at the hearings. At the outset, the physical size of the facility in question detracts from the credibility of SDG&E's position.

> Q. Thank you for the clarification that from the edge of the entire facility to the subsequent edge of the facility, I believe you mentioned that's approximately 370 feet?
>
> A. Correct. Subject to check.
>
> Q. Thank you. And what about measuring lengthwise from top to bottom, what would be that, those dimensions?
>
> A. I don't have that with me.
>
> Q. Would it be fair to say that that would be significantly more than 370 feet?
>
> A. Yes.[60]

The Talega Substation is a relatively large facility. Mr. Iliev agreed that the width of the facility is longer than the length of a football field.[61] Further, there is currently access sufficient to conduct maintenance on the substation.[62] Moreover, the Talega 230 kV breaker and a half bay meets the distance requirement for a standard 230 kV breaker and a half bay.[63] This information provides the context for SDG&E's complaint regarding drive access space.

Regarding ORA's specific recommendations for resolving the Talega substation configuration problems, Mr. Iliev conceded some key points. Mr. Iliev admitted that it is possible to replace Bank 62 with a 392 MVA transformer.

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[59] See ORA 200, at 7:11-14, fn. 7.

[60] RT at 892:2-14 (Vol. 7).

[61] RT at 892:21 - 893:2 (Vol. 7).

[62] RT at 915:12-15 (Vol. 7).

[63] RT at 927:3-16 (Vol. 7).

> Q. Okay. Is it possible for SDG&E to replace Bank 62 with a 392 MVA transformer?
>
> A. Subject to check, I would say that is possible.[64]

Further, Mr. Iliev admitted that it is possible to remove Bank 60.

> Q. The question right now: Is it possible to physically remove Bank 60?
>
> A. Yes, it is possible to physically remove Bank 60.[65]

Mr. Iliev testified that SDG&E's position regarding Bank 63 relied on an argument about impeded access:

> Q. Can SDG&E fix Bank 63 so that it has a circuit breaker on both the 230 kV and the 138 kV side?
> A. No. The reason being it would impede access.[66]

However, the Mr. Iliev admitted that the subject Bank could be removed.

> Q. Well, physically can you remove the transformer [Bank 63] all together?
>
> A. Yes.[67]

Mr. Iliev further admitted that removing a transformer would not result in an interruption of service.

> ALJ FARRAR: So just so I'm clear, by itself removing one transformer will not result in an interruption of service; is that correct?
> THE WITNESS: Physically removing the transformer, yes.[68]

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[64] RT at 899:4-7 (Vol. 7).

[65] RT at 899:24-27 (Vol. 7).

[66] RT at 898:4-8 (Vol. 7).

[67] RT at 908:28 – 909:2 (Vol. 7).

[68] RT at 913:22-27 (Vol. 7).

Mr. Iliev also conceded the basic proposition that removing a transformer would create space.

> Q. If you were to remove one transformer at the Talega substation, wouldn't you have more space to work?
>
> A. I suppose, yes. Space to do what, though, is my question.[69]

Mr. Iliev's argument about feasibility also relied on the assumption that two access routes are needed.

> Q. Okay. And how many access routes do you need for each transformer around it?
>
> A. I would like two access routes.[70]

Preferences aside, Mr. Iliev conceded that only one access route was actually needed.

> Q. Let's say hypothetically some debris came and blocked one of those access routes, could you still work on the transformer using only one access route?
>
> A. With only one access route physically I could work on the transformer.[71]

In determining whether to spend hundreds of millions of ratepayer dollars on the Proposed Project, the Commission should weigh whether a preference for multiple access routes, over a very short period of replacement time, justifies the expenditure.

Mr. Iliev also described the physical space between the disconnect and the bay as follows:

> Q. So there's 30 feet of space between the disconnect and the bay, correct?

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[69] RT at 914:3-8 (Vol. 7).

[70] RT at 909:16-19 (Vol. 7).

[71] RT at 910:1-6 (Vol. 7).

> A. Yes.
>
> Q. How large is a circuit breaker?
>
> A. Circuit breaker itself not counting the connections and the disconnects that would be required for it to connect to would be approximately 20 feet by 10 feet.[72]

Mr. Iliev confirmed that it is possible to both move and replace the subject disconnect.

> Q. But you testified that it is possible to move the disconnect, correct?
>
> A. Physically, yes, but that does not meet our safety standards and our access standards.
>
> Q. Well, what if that disconnect malfunctioned and you needed to install a new one, could you remove that disconnect and then install a new one?
>
> A. Yes. To do -- if that disconnect malfunctioned, there would be a bus outage.
>
> I would need to take the bus out of service to do said work to be able to do it safely.[73]

Mr. Iliev even elaborated on how SDG&E could plan work late at night, both during a hypothetical malfunction and absent a malfunction, consistent with ORA's position.[74]

> Q. But if the disconnect were malfunctioning, you still could do work on the disconnect, could you not?
>
> A. Yes.
>
> Q. How would you do that work?

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[72] RT at 905:16-23 (Vol. 7).

[73] RT at 906:16-28 (Vol. 7).

[74] ORA 200 at 7:22-23.

> A. I would first isolate all the energized equipment around that disconnect including the 230 kV bus above the disconnect. Let me take a step back. Because I'd be taking out the 230 kV bus, I would have to schedule it with our grid operations. And in doing so, we would -- they would recognize that all of Orange County is being fed off the other 230 kV bus. And we would find an appropriate time to do that probably in the middle of the night. Then I would schedule the buss out of service, electrically isolate the bus and anything that is also close by, possibly that farther, farthest northwest position on that bay. That would make it safe to work on that disconnect.
>
> Q. Okay. And if the disconnect were not broken, you could do all these steps as well and physically remove the disconnect, could you not?
>
> A. Yes.[75]

When evaluating the credibility of SDG&E's position that it does not have enough space to fix the Talega substation without the Proposed Project, it is useful to review prior projects in that substation that SDG&E admittedly did have enough space to complete.

> Q. Okay. Mr. Iliev, has SDG&E installed any major components of the Talega Substation within the past five years?
>
> A. Yes.
>
> Q. What has it installed within the past five years?
>
> A. Most recently the synchronous condenser, 230 kV. In addition, there was work on the 138 kV/[69] kV transformer bank.[76]

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[75] RT at 907:8 – 908:6 (Vol. 7).

[76] RT at 893:3-11 (Vol. 7).

Mr. Iliev admitted that SDG&E "made the space" to conduct that work.[77] The fact that the work was eventually complete demonstrates, de facto, that it was feasible. SDG&E's ability to install additional facilities at the Talega substation calls into question SDG&E's argument that it is unable to reconfigure existing facilities.

III. Selection of Alternative / If the Commission Selects a Project, which Alternative Should it Select?

SDG&E has not justified its Proposed Project. While SDG&E points to a number of risks that it perceives, SDG&E's approach of building more transmission lines in the same approximate geographic area is unjustified. Further, as ORA pointed out in its testimony, SDG&E's approach is:

> [A]t odds with the general approach of diversity in addressing SDG&E's perceived third party actions that could impact the reliability of the Talega Substation. In order to avoid or mitigate these potential third party actions, one approach of diversity would be to spread the mitigating measures throughout SDG&E's transmission system, so that the risks and vulnerabilities of the infrastructure systems from these potential third party actions can be reduced. SDG&E's approach is to concentrate all the mitigating measures together in the same approximate geographic locations. Doing so will not effectively mitigate the risks and/or vulnerabilities of SDG&E's transmission system regarding potential third party actions.[78]

If the Commission authorizes a project, it should select the cost-effective Trabuco Alternative as proposed by ORA. "The Trabuco Alternative as proposed by the Office of Ratepayer Advocates (ORA), would upgrade the 138 kV Trabuco Substation to 230 kV, and loop in the upgraded Trabuco Substation to one of the San Onofre – Santiago

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[77] RT at 896:7-10 (Vol. 7).

[78] ORA 200, at 11:14-23

transmission lines."[79] This alternative would provide "two real independent power supply sources to the SOC area: one from the Talega Substation in the south of SOC and the other from the upgraded Trabuco substation in the north of SOC."[80] The Recirculated Draft Environmental Impact Report designated Alternative J, a substantially similar proposal, as the Environmentally Superior Alternative.[81]

A. The Trabuco Alternative is Less Expensive than the Proposed Project.

SDG&E greatly inflates the cost estimate for the Trabuco Alternative. At hearings, ORA established that aside from a 10% error range, SDG&E factored in a 30% contingency in estimating most of the Trabuco Alternative costs. The fact that a contingency was factored in was uncovered during cross-examination by ORA:

> Q. … Can you direct me to where in Section 9 of your testimony in SDG&E-3 you indicate the contingency levels?
>
> A. Well, I don't include that in the -- sorry. The values you see here include that level of contingency in it.
>
> Q. What level of contingency?
>
> A. The 30 percent.[82]

Further questioning by ORA revealed that SDG&E had added a 30% contingency for its estimated cost of constructing a 230/138/12 kV substation at Trabuco and the relocation of the existing distribution circuits, its approach for interconnecting at a rebuilt Trabuco Substation with an SCE transmission line, a proposed voltage control device at a rebuilt Trabuco Substation.[83] SDG&E's cost estimates for work on the Capistrano

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[79] ORA 201, at 2:10-12.

[80] ORA 200, at 17:4-7.

[81] *Recirculated Draft Environmental Impact Report* (August 2015), A.12-05-020, at 2-173.

[82] RT at 688:4-9 (Vol. 5).

[83] RT at 688:12 – 691:24 (Vol. 5).

substation (including proposed voltage support that could have also been placed at a different substation) applied a 0-30 percent contingency.[84]

Putting aside SDG&E's inflated costs for the Trabuco Alternative, ORA has already estimated that the cost for its proposal would be far less than the Proposed Project.[85] ORA has also explained that:

> Based on ORA's analysis, the Trabuco Alternative would cost less. Compared to SDG&E's Proposed Project which would construct 7.5 miles of double circuit 230 kV transmission lines and would upgrade the 138kV Capistrano Substation to 230 kV, the Trabuco Alternative would construct only approximately 2,000 feet of 230 kV transmission lines and upgrade the 138 kV Trabuco Substation to 230 kV. Therefore, the Trabuco Alternative would cost less than the SDG&E Proposed Project.[86]

SDG&E has not refuted ORA's position that the Trabuco Alternative would be less costly than the Proposed Project. However, SDG&E has conceded that cost-effectiveness should be considered. This was after testifying that CAISO "deals with the cost of mitigation."

> Q. Thank you. Do you think that it's important to consider cost-effectiveness in developing mitigation measures?
>
> A. As a part of transmission planning, the CAISO deals with the cost of mitigation measures. Through the transmission planning process the CAISO -- we present projects. The CAISO evaluates them, and they either accept or reject them. The prices included in the -- the cost of the project is presented for evaluation.
>
> Q. But that wasn't my question. My question was do you think it's important to consider cost-effectiveness in developing mitigation measures?

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[84] RT at 689:17 – 690:4 (Vol. 5).

[85] See ORA 200, at 18, Table 1.

[86] ORA 201, at 12:3-9.

> A. My personal feeling, is that the question?
>
> Q. Well, you're put forth for your opinions on this matter. So please opine.
>
> A. Okay. I represent SDG&E here today. And I do believe that we do the best we can to keep our cost reasonable.
>
> Q. So as you sit here today, you can't tell me one way or the other whether you think it's important to consider cost-effectiveness in developing mitigation?
>
> A. Yes, I believe it's important to consider cost-effectiveness when we develop projects.[87]

Cost-effectiveness is critical in making the decision to approve or deny a project. ORA has testified that under the Proposed Project:

> [T]here would be excess power supply capabilities to the SOC area that are not needed. This excess power supply would lead to unnecessary transmission over build and sunk costs at ratepayers' expense. Because the proposed project does not address the actual engineering problems at the Talega Substation, it would result in overbuilding unneeded transmission.[88]

In contrast, Trabuco Alternative is more cost effective than the Proposed Project. As described below, it would more effectively improve power supply reliability and provide a more reliable, and more optimally located, second source of power.[89]

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[87] RT at 288:8 – 289:8 (Vol. 2).

[88] ORA 200, at 9:5-10.

[89] See ORA 201, at 12:10-25. The Trabuco substation also currently serves more load than the Capistrano substation. RT at 103:14-18. (Vol. 1).

B. The Trabuco Alternative Provides a Real Second Power Source to the South Orange County Area, While the Proposed Project Does Not.

1. The Trabuco Alternative Provides for an Electrically Independent Second Source.

The Proposed Project will provide two sources of 230 kV power supply that are not truly independent of one another.[90] Mr. Mee testified that under the Proposed Project "[t]he first proposed 230 kV transmission line would be the tap-off of the Escondido-Talega transmission line … [and] if there is an outage on the Escondido-Talega transmission line, the tap-off transmission line would also lose power, so both Talega Substation and Capistrano Substation would lose one 230 kV power supply at the same time."[91]

In contrast, under the Trabuco Alternative, there is greater electrical independence. As Mr. Mee explained in his testimony:

- Under the Trabuco Alternative, the 230 kV Trabuco Substation power supply to the SOC area will be looped into one of the San Onofre – Santiago transmission lines, which is not directly interconnected to Talega Substation. The electrical independence between the Talega and Trabuco substations ensures that if one of the substations is out of service, the other one will not be impacted electrically due to the outage of the first substation and would be able to continue the power supply to the SOC area.[92]

[90] ORA 200, at 9:11-21.

[91] ORA 200, at 9:22-26.

[92] ORA 201, at 12:14-21.

2. The 230 kV Transmission Lines Supplying Both the Talega and San Juan Capistrano Substations Share the Same Towers and are thus Vulnerable to Catastrophic Events.

Aside from electrical independence, Mr. Mee also testified about a vulnerability related to facilities sharing the same towers under SDG&E's Proposed Project.

> The second proposed 230 kV transmission line would be the extension of one of the existing double-circuit 230 kV San Onofre Switchyard-Talega transmission lines (see Figure 2). The double-circuit San Onofre Switchyard-Talega transmission lines share the same towers. If one of the towers falls down or is damaged by a wildfire or by other natural disaster at the ROW, the two transmission lines, including the extension from Talega Substation to Capistrano Substation, would lose power at the same time. As a result, both Talega and the upgraded Capistrano Substation will lose one power supply at the same time.[93]

During cross-examination, this key vulnerability of the Proposed Project was identified:

> Q. The transmission lines going from San Onofre to Capistrano in the proposed SOCRE Project, they are the same right-of-way as the transmission lines that go and will terminate at Talega. And they turn towards Capistrano in the area that is immediately west of and adjacent to the Talega Substation?
>
> A. To the best of my recollection, yes.[94]

The potentially catastrophic consequences of this vulnerability were also examined:

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[93] ORA 200, at 10:1-8.

[94] RT at 50:16-25 (Vol. 1).

> Q. Could Talega be removed from service because of arcing or other fire damage to the 230 kV lines that serve Talega?
>
> A. Yes, it could.
>
> Q. Aren't the 230 kV lines that serve Talega located in the same portion of SDG&E's fire threat zone as the 230 lines that are proposed to serve Capistrano under the SOCRE Project to Talega, not beyond Talega?
>
> A. To Talega? Yes, they are.
>
> Q. Okay. Wouldn't the arcing or fire damage on 230 kV lines that serve Talega also cause arcing or fire damage to the 230 kV lines that will serve Capistrano under the SOCRE Project?
>
> A. My work with the electric lines over a dozen years with SDG&E, any line out there is susceptible under the right conditions.
>
> Q. So that is a yes?
>
> A. So that would be a yes.[95]

Mr. Jontry confirmed the issue under cross examination by ORA:

> Q. Okay. Are you aware as to whether or not the SONGS-San Juan Capistrano transmission lines and the SONGS-Talega transmission line would share the same towers?
> A. For a portion of the right-of-way that is correct, yes.
> Q. Do you admit that for that portion if towers were to fall down that the power could be interrupted on both those lines?
> A. Yes. It would be an N-2 power load failure, yes.[96]

This identified vulnerability argues against adoption of the Proposed Project.

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[95] RT at 51:22 – 52:14 (Vol. 1).

[96] RT at 101:2-13 (Vol. 1). Subsequently, Mr. Jontry did tentatively apply the issue to the Trabuco Alternative. RT at 101:14-19 (Vol. 1). However, under the Trabuco Alternative as envisioned by ORA, the SONGS-Santiago line would not share the same towers as the SONGS-Talega line. Thus, the probability of a failure on two sets of towers, at the same time, would be lower than the probability of failure for one set of towers.

3. The Proposed Project Results in Three Transmission Lines, Near the Talega Substation, that are Vulnerable due to Geographic Proximity.

In his testimony, Mr.Mee also identified a vulnerability of the Proposed Project near the Talega substation.

> From a geographic perspective, since all three 230 kV transmission lines would go through Talega Substation first and are geographically close to each other, the Proposed Project may not be able to effectively improve power supply reliability for the SOC area. The new 230 kV double circuit transmission lines supplying power to the upgraded Capistrano Substation would be extensions of the two existing transmission lines (the single circuit Escondido-Talega transmission line and one of the double circuit San Onofre Switchyard-Talega transmission lines). Thus, if [a] disaster such as fire, explosion, earthquake, vandalism, or terrorism occurs at the existing transmission lines, near the Talega Substation, the existing transmission lines as well as the new transmission lines connected to the upgraded Capistrano Substation could lose power at the same time. This would result in both the Talega Substation and the Capistrano Substation losing power at the same time and the whole SOC area load being disrupted.[97]

This type of vulnerability is mitigated under the Trabuco Alternative. During cross-examination by ORA, SDG&E's witness Mr. Iliev testified regarding the geographic proximity issue at Talega, as to seismic risk.

> Q. Okay. You understand that an earthquake can cause a utility pole to fall to the ground, do you not.
>
> A. Again, I think you should talk to Willie Thomas about seismic activity with regard to poles.[98]

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[97] ORA 200, at 10:9-21.

[98] RT at 917:9-15 (Vol. 7).

> …
>
> Q. Okay. An earthquake can cause a utility pole fall to the ground, can it not, Mr. Iliev?
>
> MR. RAUSHENBUSH: Objection, outside the scope of his testimony. It is on page 15 line 3 Item 5 is the scope of this testimony.
>
> ALJ FARRAR: That is fine. If the witness knows he can answer, or if has a reasonable belief he can answer.
>
> THE WITNESS: All I can point to is my experience in my testimony.[99]
>
> …
>
> So with regarding your testimony about seismic activity, can such seismic activity cause a utility pole to fall to the ground, in your view?
>
> A. Yes.
>
> Q. Thank you.
>
> Aren't the SONGS-Talega, SONGS-Capistrano and Escondido, Talega, Capistrano all within a half mile radius of the Talega Substation under the proposed project?
>
> A. They are close by, yes.
>
> Q. So if an earthquake in that area where to knock out all of those lines, that would result in an outage of the entire South Orange County area, right?
>
> A. If an earthquake where to knock out those lines, yes.
>
> Q. Thank you.[100]

Furthermore, with the Proposed Project in place, SDG&E could not guarantee that service would be restored within 24 hours under this

[99] RT at 917:26 – 918:8 (Vol. 7).

[100] RT at 919:27 – 920:17 (Vol. 7).

scenario.[101] This issue adds more weight to the argument against the Proposed Project.

4. The Trabuco Substation is Geographically Separate from the Talega Substation.

Mr. Mee also testified regarding certain geographic advantages of the Trabuco Alternative:

- Also, since the Trabuco Substation and Talega Substation are approximately 10 miles apart from each other; it is less likely for natural disasters such as fires or earthquakes to dismantle both substations simultaneously.[102]

SDG&E failed to refute ORA's position in its testimony, or at hearings. Indeed, Mr. Thomas testified that he did not know about a basic advantage of this distance during cross-examination:

> Q. The distance. How about the distance between Trabuco and Talega. Do you know what that distance is?
> A. It is subject to check, but as I recall the Talega to Capistrano is about eight miles, 7.8 miles. And then from Talega or Capistrano to Trabuco is about four miles.
> So it is roughly 10 to 11 miles.
> Q. Okay. Taking --
>
> A. From Trabuco to Talega.
>
> …
>
> Q. Okay. You mentioned the distance of 10 to 11 miles. So would you agree that the probability that the three transmission lines and the San Onofre-Trabuco and the Trabuco-Santiago lines going out at the same time would be lower than the probability of just the three transmission lines associated with the proposed project going out?
> A. I can't answer that.

[101] RT at 921:5-13 (Vol. 7).

[102] ORA 201, at 12:22-25.

> Q. Well, you said you can't answer that. But you're here representing the company to answer questions about the project. So is it that you can't answer it because the answer is yes the probability would be lower, because you simply don't know or some other reason?
>
> A. I simply don't know.[103]

Of course, the probability of the SOC area being out of service under certain catastrophic events such as fire, explosion, earthquake, vandalism, or terrorism would be lower under the Trabuco Alternative. SDG&E's refusal to answer questions with this obvious answer should be accorded no weight.

C. The Trabuco Alternative will not Introduce any Significant Loop Flow, Path Rating/Overloading or Market Congestion Issues.

1. The Trabuco Alternative Will not Introduce Significant Loop Flow Issues.

SDG&E has identified loop flow as a potential concern with the Trabuco Alternative. However, as Mr. Mee explained in his testimony, "[l]oop flow and path rating issues of the Trabuco Alternative are of minimal concern."[104] Currently, there are "four transmission lines connecting the San Onofre Switchyard to three 230 kV substations in the SCE service territory."[105] These are: San Onofre – Viejo; San Onofre – Serrano; (3) San Onofre – Santiago #1; and San Onofre – Santiago #2.[106] Under the Trabuco Alternative, the substation would be "interconnected to one of the San Onofre –

[103] RT at 679:26 – 680:7, 681:2-18 (Vol. 5).

[104] ORA 201, at 6:12-13.

[105] ORA 201, at 6:13-14.

[106] ORA 201, at 6:16-19.

Santiago transmission lines, [and] … SDG&E's SOC 138 kV sub-transmission network could be seen as the fifth path between the SDG&E and SCE service territories."[107]

SDG&E's SOC sub-transmission lines would operate at 138 kV, compared to the other four transmission lines, which operate at 230 kV.[108] Considering equivalent impedance, the power flowing between the SCE service territory and the SDG&E service territory through the SOC 138 kV sub-transmission lines" would be significantly lower.[109]

Mr. Mee acknowledged that loop flow could become an issue in the unlikely event that there was "no load at all in the SOC area."[110] He explained that:

> Under a very extreme scenario, if all the above four 230 kV transmission lines were out of service and the SOC network is still interconnected to both SDG&E and SCE service territories, the SOC network would be the only path for power transfer between the two service territories. However, the probability that all the four 230 kV transmission lines would be out-of-service at the same time is minimal. Even under this extreme scenario, the SOC area load will absorb power from both SDG&E service territory (through Talega Substation) and SCE service territory (through Trabuco Substation). There is no power flowing through the SOC network under this scenario.[111]

Mr. Mee also pointed out that "in the Western Interconnection there are a number of places where two different voltage level transmission lines operate in parallel."[112]

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[107] ORA 201, at 6:21-24.

[108] See ORA 201, at 6:24-27.

[109] ORA 201, at 7:1-5.

[110] ORA 201, at 7:6-7.

[111] ORA 201, at 7:10-18.

[112] ORA 201, at 7:19-20.

Ultimately, when there are more than one power sources to a local area, it is difficult to absolutely avoid loop flow issues. This is also true for the Proposed Project. For the Proposed Project, under some outage scenarios, power could flow from Escondido Substation to the upgraded San Juan Capistrano Substation, then flow through the 138 kV SOC local network, and then to Talega Substation, and then further flow to San Onofre Switchyard. SDG&E does not refute the possibility of loop flow associated with the Proposed Project.

2. The Trabuco Alternative Will not Cause Significant Path Rating or Overloading Issues.

Regarding SDG&E's arguments on path rating, ORA testified as follows:

> SDG&E also asserts that interconnecting the Trabuco Substation to one of the San Onofre –Santiago 230 kV transmission lines will impact the path rating for Path 43 and Path 44. SDG&E's concerns are no longer valid because of the retirement of the San Onofre Nuclear Generating Station 2 (SONGS), which made the path rating of Path 43 and Path 44 meaningless. As a result of the retirement of SONGS, SDG&E, SCE, and the ISO have now requested the Western Electric Coordinating Council (WECC) to de-list the path ratings for Path 43 and Path 44. Consequently, in February 6 2015, the WECC de-listed the path ratings for Path 43 and Path 44. Now that the path ratings for the two paths are de-listed, there is no maximum power flow requirement on the four 230kV transmission lines. This should alleviate SDG&E's concerns regarding Trabuco Alternative's impact to the de-listed path ratings.[113]

No party has presented any compelling testimony in opposition to ORA's perspective on this issue. However, on a related topic, CAISO pointed to certain

[113] ORA 201, at 8:4 – 9:11 (internal citations omitted.)

overloads that were modeled.[114] At hearings, ORA questioned Mr. Sparks about certain assumptions in the modeling:

> Q. Mr. Sparks, I would like to turn your attention to page 8 Table 1 of your supplemental rebuttal testimony. I believe that has been marked as Exhibit 505.
>
> A. Okay.
>
> Q. Currently marked as Appendix A based on your corrections, correct?
>
> A. Correct.
>
> Q. Okay. You indicate, do you not, that this table assumes 1,800 megawatts northbound flow via the SONGS path, correct?
>
> A. That is correct.[115]

Mr. Sparks did not know whether that assumption would be proved true for 2016, 2017, 2018 or 2019.[116] He admitted that for 2016 and 2017, CAISO "did not consider that timeframe."[117] When forced to characterize the risk of having 1,800 MW northbound flow via the SONGS path, Mr. Sparks testified as follows:

> MR. MOLDAVSKY: Q. I'm afraid that didn't quite answer the question that I asked, which was you can't tell me how many times per year that would happen after 2019; correct?
>
> MR. PINJUV: Objection, asked and answered.

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[114] See, e.g., Exhibit CAISO 505, *Oct 2, 2015 Supplemental Rebuttal Testimony of Robert Sparks* ("CAISO 505"), at 8, Table 1.

[115] RT at 321:16-27 (Vol. 3).

[116] RT at 325:15 – 326:6 (Vol. 3).

[117] RT at 325:28 – 326:1 (Vol. 3).

> ALJ FARRAR: And unfortunately, the witness's answer is not -- has not actually responded. So it was asked, but not answered.
>
> Please answer the question.
>
> THE WITNESS: No, no more than a weatherman can tell you how many times one-in-a-hundred year drought or one-in-a-hundred year flood is going to happen. Planning looks at risks, and that's what I'm talking about here.[118]

CAISO's characterization of the risk indicates that a very low probability event was considered in its analysis. Mr. Sparks also appeared to admit that the subject analysis was a contingency case.

> Q. Okay. That analysis that you just described is a contingency case; right?
>
> A. It could -- yeah, we took a contingency in the base case. If you want to refer to it as a contingency case, I think I'll understand what you mean.
>
> Q. Well, I may want to refer to it as a contingency case, but I'm asking if you believe it's a contingency case.
>
> A. Just to be precise, I described what I believe it is.
>
> Q. So it's inaccurate to describe it as a contingency case in your view?
>
> A. There are many contingencies. This is a transmission contingency case. There could be other -- other contingencies, so I just want to make sure that -- that we don't misrepresent what's in this table.[119]

Mr. Sparks also admitted that the analysis was not as thorough as it could have been.

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[118] RT at 329:2-19 (Vol. 3).

[119] RT at 331:3-20 (Vol. 3).

> They were not -- this particular Alternative J which we're talking about here was not advocated by anybody, so we didn't feel compelled to go through more in depth analysis.[120]

At hearings, ORA introduced Exhibit ORA 219, an Excerpt from the 2014 WECC Path Rating Catalog. The indicated Transfer Limit, south to north was 2,440 MW.[121] Notably, the 2,440 MW transfer limit identified in the WECC catalog prior to the path rating being de-listed is greater than the 1,800 MW assumption in the CAISO studies discussed above. Thus, even given the CAISO's extreme assumption, the path rating should not be violated under the Trabuco Alternative.

Further, regarding certain other overloading problems identified by CAISO, ORA clarified that such problems would occur under both the Trabuco Alternative and the Proposed Project.

> Q. Okay. I'd like to direct your attention to page 12 and 13 of Exhibit 505.
>
> ALJ FARRAR: Do you see those pages?
>
> THE WITNESS: Yes. Figures AA-1 and AA-2 I believe.
>
> …
>
> MR. MOLDAVSKY: Q. Okay. You've reviewed both these diagrams that were previously identified?
>
> A. Yes.
>
> Q. Okay. So both the SOCRE Project and the Trabuco alternative have an overloading concern on SCE's Ellis-Santiago and Ellis-Johanna lines; correct?
>
> A. Yes. I think that's better exhibited in the tables that precede these figures, but yes.[122]

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[120] RT at 249:17-21 (Vol. 2).

[121] Exhibit ORA 219, *Excerpt from the 2014 WECC Path Rating Catalog*.

[122] RT at 350:11-15, 351:6-16 (Vol. 3).

If, in CAISO's view, both the Proposed Project and the Trabuco Alternative have the same identified problem, then this testimony should not be weighed against only the Trabuco Alternative, but the Proposed Project as well.

Also, CAISO's disagreement with the Trabuco Alternative seems in part based on the following concept outlined in Mr. Spark's testimony:

> As described in the direct testimony of Neil Millar on behalf of the CAISO, any alternative paralleling SCE 230-kV system with the SDG&E's SOC 138 kV system would materially impact the 230 kV transmission path between SCE's LA Basin and the San Diego area.[123]

However, CAISO's witness Mr. Millar contradicted this testimony during cross examination by ORA:

> Q. Mr. Millar, would any alternative parallel (sic) with Southern California Edison's 230 kV system with SDG&E's South Orange County 138 kV system materially impact the 230 kV transmission path between SCE's L.A. Basin and the San Diego area?
>
> A. They could.
>
> Q. I understand they could, but that wasn't my question. …
>
> Would any alternative paralleling Southern California Edison's 230 kV system with SDG&E's South Orange County 138 kV system materially impact the 230 kV transmission path between Southern California Edison's L.A. Basin and the San Diego area?
>
> A. Yes. And my answer is – that's the question. And my answer is they could ***depending on the configuration.*** Any configuration that's proposed would need to be studied. There are many criteria that need to be considered.
>
> Q. Is it possible for there to be an alternative paralleling Southern California Edison's 230 kV system with SDG&E's South Orange County 138 kV system that would not materially impact the 230 kV system – excuse me -- the 230

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[123] CAISO 505, at 3:14-17.

> kV transmission path between SCE's L.A. Basin and the San Diego area?
>
> A. This is a new concept, so off the top of my head, I would say that by introducing a back-to-back HBDC converter on the path would ***could achieve that.*** There may be other alternatives that also involve far more expensive technologies, but I -- this is the quickest answer I can give in 30 seconds.[124]

Mr. Millar's testimony that it may be possible not to materially impact the transmission path contradicts Mr. Sparks' characterization that any alternative would do so. The Commission should not overvalue the CAISO's attempt to discredit the Trabuco Alternative, based on unproven impacts on the transmission path.

3. SDG&E has not Established that the Trabuco Alternative Will Cause Market Congestion.

SDG&E has not supported its argument regarding market congestion. Under cross-examination by ORA, SDG&E immediately conceded that it had not conducted any economic studies to support its conclusion.

> Q. October 19th, 2015, that would be SDG&E-05, page 10, at line 23.
>
> A. I'm there.
>
> Q. Okay. You state:
>
> Limiting flow on Path 43 transmission lines would introduce expensive market congestion and reduce the number of generation resources available to service SCE load. Correct?
>
> A. That's correct.
>
> Q. Has SDG&E conducted any economic studies to support this assertion?

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[124] RT at 431:28 – 433:8 (Vol. 3) (emphasis added).

> A. They have not.[125]

SDG&E also admitted that Southern California Edison ("SCE") did not participate in its "study" or "assessment."[126] SDG&E admitted under cross-examination by ORA that it had no underlying data in support of its assumption.

> Q. So you don't have any of the underlying data to support this assumption from SCE's system?
>
> A. To -- I don't know what the congestion cost will be. We have not done a study to evaluate what the cost will be. This is not our project. We are fearful that we will cause congestion. We don't know for certain at this point.[127]

SDG&E's disquietude about market congestion is not supported by any underlying data. Without such support, SDG&E's testimony on this topic should be accorded no weight. Further, SDG&E's attempt to bolster this testimony on re-direct with reference to Mr. Smith's "experience" should also be accorded no weight.[128] On this record, experience is not a substitute for actual data.

In any event, no party has presented compelling testimony that SCE's system would be materially impacted by the Trabuco Alternative.

D. The Trabuco Substation Configuration is Acceptable.

Mr. Mee has presented testimony regarding the proposed Trabuco Substation configuration.

> ORA recommends the following electrical configuration for the Trabuco Alternative, which is indicated in Figure 2 below.

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[125] RT at 302:7-21 (Vol. 2).

[126] RT at 303:16-19 (Vol. 2).

[127] RT at 303:27 – 304:7 (Vol. 2).

[128] RT at 1275:3-18 (Vol. 8).

- Acquire the AT&T parking lot for the 230 kV switchyard;
- Install 230 kV circuit breakers at the 230 kV switchyard, using breaker-and-a-half configuration;
- Install one 230/138 kV 392 MVA transformer (Transformer #1);
- Construct approximately 2,000 feet of 230 kV double circuit overhead transmission lines along the Camino Capistrano route to loop-in one of the San Onofre – Santiago transmission lines to the 230 kV switchyard of the Trabuco Substation;
- Shift sub-transmission line 13833 (TL13833) from its current terminal position to the spare terminal position, and connect the terminal position vacated by the TL13833 to the 138 kV output of the 230/138 kV Transformer #1;
- Upgrade protection, control, and communication functions;
- For potential load growth in the future, leave space for an additional transformer (Transformer #2) and an additional 138 kV circuit breaker in the 230 kV switchyard. The 138 kV output of the Transformer #2 would be connected to the 138 kV Bus South.[129]

During cross-examination by ORA, Mr. Iliev testified that ORA's proposal was similar to other substations in SDG&E's service territory, other than Talega.

> A. According to the Trabuco Alternative Charles Mee, October 2nd. There are modifications in the Trabuco yard including new transmission poles to connect the 230 to 138 kV transformers and relocation of 138-33 into a different position.
>
> Q. Okay. What about the bus configuration?
>
> A. The bus configuration is generally the same as a single breaker single bus.
>
> Q. Thank you.

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[129] ORA 201, at 9:14 – 10:11.

> Now, going broader, the other 138 switchyards the SOC area, they are similar to the Trabuco Substation in the bus configuration, correct?
>
> A. Similar, yes excluding Talega.
>
> Q. Okay. And excluding Talega, those other 138 kV substations are single bus configuration, correct?
>
> A. Yes.[130]

No party has effectively refuted ORA's proposal regarding the Trabuco substation configuration.

E. SDG&E Should Have Coordinated with CAISO and SCE in Order to Demonstrate the Feasibility of the Trabuco Alternative.

At hearings, Mr. Jontry admitted that SDG&E had not done sufficient work on the Trabuco Alternative:

> My understanding is that since the Trabuco, one of the Trabuco alternatives was not proposed by SDG&E, it is not our burden to prove it could be conducted in a -- necessary studies could be conducted in a timely fashion.[131]

Regarding transmission planning on the Trabuco Alternative, SDG&E's Mr. Thomas testified that SDG&E had not "done detail engineering, land rights research, or even communicated with SCE yet to determine the feasibility."[132]

Such statements indicate a lack of effort on SDG&E's part to promptly establish the feasibility of the Trabuco Alternative. The

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[130] RT at 1059:22 - 1060:13 (Vol. 8).

[131] RT at 105:20-25 (Vol. 1).

[132] RT at 652:7-9 (Vol. 5).

Commission could order SDG&E to finalize this alternative, regardless of SDG&E's lack of interest.[133] Mr. Mee has testified on this point:

> Both SDG&E and SCE, among other utilities, turned over the operational control of their high voltage transmission facilities to the California Independent System Operator (ISO) before the year 2000. SDG&E and SCE are now obligated to coordinate with each other and collaborate with the ISO to develop the high voltage transmission grid. The ISO conducts transmission studies every year. SDG&E and SCE participate in these annual transmission studies and work together with the ISO in planning the transmission grid and coordinating transmission projects. Thus, SDG&E has ample experience in collaborating with SCE and with the ISO in transmission planning to interconnect the Trabuco Substation to SCE transmission systems, which are part of the ISO controlled grid. SDG&E has not shown that ORA's proposed interconnection would take years to accomplish.[134]

Mr. Mee has also noted the following:

> [T]he Commission should require SDG&E and SCE to collaborate with the ISO on the engineering design of the Trabuco Alternative. SCE owns the San Onofre – Santiago transmission lines and SDG&E owns the Trabuco Substation. The ISO is the system operator for the transmission facilities. The utilities are obligated to collaborate with the ISO on transmission planning and transmission project development in California. In fact, SDG&E, SCE, and ISO are collaborating continuously in the ISO annual transmission planning processes and communicate frequently with each other. The Commission should require SDG&E and SCE to continue to collaborate with the ISO on the development of the Trabuco Alternative. ***Regardless of who constructs the 230 kV switchyard at the Trabuco Substation and the approximately 2,000 feet of transmission lines that will loop in one of the San Onofre – Santiago transmission lines to***

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[133] See Cal. Pub. Util. Code § 701.

[134] ORA 201, at 3:13-22.

the 230 kV switchyard, the associated capital and operation and maintenance costs that are found to be just and reasonable would be allocated to all the transmission customers of the ISO controlled grid.[135]

IV. CONCLUSION

SDG&E has not met its burden in this proceeding. For the reasons described above, the Proposed Project should not be approved. If the Commission selects an alternative, the Trabuco Alternative, as proposed by ORA should be adopted.

Respectfully Submitted,

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[135] ORA 201, at 12:28 – 13:14 (emphasis added).