Application No.:	A.15-04-013
Exhibit No.:	SCE-
Witnesses:	Dana Cabbell Mustafa Ali Bradford Thompson Kathy Hidalgo Roman Vazquez Gary Busteed

SOUTHERN CALIFORNIA EDISON®

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(U 338-E)

Southern California Edison Company's (U 338-E) Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

PUBLIC VERSION

Before the

Public Utilities Commission of the State of California

Rosemead, California
August 16, 2019

SCE's Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Table of Contents

	Section	Page	Witness
I.	Introductory Statement	1	
II.	SCE's Rebuttal Testimony Regarding The Need For RTRP As Justified By Applicable Electrical Planning Criteria, The Unreasonableness Of System Alternatives Suggested In Other Testimony, And The Qualifications Of Dana Cabbell	3	D. Cabbell
	A. NERC And CAISO Reliability Standards Are Not Applicable When Assessing Local Radial Distribution System Needs	6	
	B. RTRP Is An Appropriate Solution For Meeting RPU System Needs Even Under NERC And CAISO Reliability Standards	8	
	C. Transferring RPU Load To SCE's San Bernardino System Would Not Address Base Case Overload Conditions And Would Only Address Posited Contingency Events For A Limited Time.	12	
	1. The *Lewis Testimony* Does Not Recognize Limitations On How Much Load Can Be Transferred.	12	
	2. The *Lewis Testimony* Does Not Recognize The Reliability Concerns That A Transfer Of Some Riverside Load Would Create.	17	
	D. Revising SOB 32 To Allow Paralleling Of Three Vista Substation Transformers Would Reduce Reliability For Customers Served Out Of Vista Substation And Would Require SCE To Utilize Equipment In An Inefficient And Unreasonable Manner.	20	
	E. The Suggestion That Simple Switching Procedures Could Accommodate Adequate Load Transfers Is Based On Outdated Demand Information And Would Still Result In Unacceptable Load Shedding.	27	
III.	SCE's Rebuttal Testimony Regarding SCE's Satisfaction Of Various Regulatory Requirements Relevant To Wildfire And The Qualifications Of Mustafa Ali	31	M. Ali

SCE's Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Table of Contents (Continued)

Section		Page	Witness
A.	Compliance With Existing Regulations Applicable Across SCE's Service Territory Reduces The Risk Of Wildfire	33	
B.	Compliance With The Recently Revised Public Utilities Code Section 8386 Is Specifically Intended To Reduce The Risk Of Wildfire	34	
C.	Coordination Between The Commission And CAL FIRE Promotes Continuous Improvement In SCE's Efforts To Mitigate Wildfire Risk	37	
D.	SCE Tailors Its Actions To Mitigate Wildfire Risk Pursuant To An Analysis Of Risks Posed And Transmission Facilities Are Involved In A Relatively Small Percentage Of Ignition Events In SCE's Service Territory	38	
E.	SCE Does Not Propose Additional Undergrounding In The Case Of RTRP To Further Mitigate Wildfire Risk	44	
IV.	SCE's Rebuttal Testimony Regarding The Anticipated Cost Of The Acquisition Of Real Property Rights In Support Of The Construction Of Project Alternatives, The Impacts Of Overhead Transmission Lines On Property Values, And The Qualifications Of Bradford Thompson	47	B. Thompson
A.	Anticipated Costs of the Acquisition of Real Property Rights in Support of the Project Alternatives Are Likely to be Significantly Less Than Intervenors Argue	49	
B.	Intervenors' Projections of Impacts of Overhead Transmission Lines on Property Values and Potential Development Along the I-15 Corridor Are Speculative and Unsupported	55	
V.	SCE's Rebuttal Testimony Regarding The Maximum Prudent And Reasonable Cost Of RTRP And The Estimated Cost Of The Project Alternatives And The Qualifications Of Kathy Hidalgo	65	K. Hidalgo
A.	Mr. Platt's Assertions that SCE's Estimated Costs Are Excessive Are Based on Methodological Flaws and Assumptions Unsupported By RTRP's Facts	68	

SCE's Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Table of Contents (Continued)

Section			Page	Witness
	1.	SCE's estimated cable costs are based on actual bids and more likely to be accurate than non-binding quotes and theoretical assumptions	70	
		a) Cable Vendor Unavailability Risk	70	
		b) Cable Material Costs	73	
	2.	SCE appropriately applied contingency to its known risk costs	74	
	3.	Intervenor's estimates of sales tax are improper	77	
	4.	Intervenors estimates of "Owners Agent" costs are theoretical and are inferior to SCE's project-based estimates	78	
	B.	Franchise Agreement With The City of Jurupa Valley And The Risk Of An Unsupportive Local Government	80	
	C.	Significant Ratepayer Impact Argument	82	
VI.	SCE's Rebuttal Testimony Regarding The RTRP Project's Estimated Scope And The Qualifications Of Roman Vazquez		85	R. Vazquez
	A.	Mr. Platt's Proposed Vault Size And Count Reduction Is Based On Inadequate Engineering Therefore His Estimated Cost Reductions For RTRP Are Without Merit	86	
	B.	SCE's Hard Digging Risk Costs Are More Likely To Be Accurate Than Mr. Platt's As They Are Based On Site-Specific Field Investigations	89	
	C.	Mr. Webb's Assumption That 150-Foot Right-Of-Way Is Required In Support Of The Riser Poles Is In Error	90	
	D.	Mr. Webb Over-Estimates The Amount Of Land Requiring A Permanent Easement By Mistakenly Including Ground Disturbance Areas Outside Of SCE's Proposed 100-Foot Right-Of-Way.	91	

SCE's Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Table of Contents (Continued)

	Section	Page	Witness
VII.	SCE's Rebuttal Testimony Regarding The RTRP Project's Consistency With Environmental Justice Principles, And The Qualifications Of Gary Busteed	95	G. Busteed

ATTACHMENTS

Attachment I-1 *Declaration of Erik Takayesu Regarding the Confidentiality of Certain Data*

Attachment II-1 *NERC guidance memorandum dated April 10, 2012*

Attachment II–2 *NERC BES Definition Implementation Guidance Manual*

Attachment II-3 *FERC Order On Local Distribution Determination in Docket No. RC15-1-000*

Attachment II-4 *Excerpts from SCE's Transmission Planning Criteria (CONFIDENTIAL)*

Attachment II-5 *California ISO Planning Standards (Effective September 6, 2018)*

Attachment II-6 *Excerpts from SCE's Subtransmission Planning Criteria (CONFIDENTIAL)*

Attachment II-7 *SCE Response to Data Request Set Cal Advocates 004, Question 02*

Attachment II-8 *Hypothetical San Bernardino Transfer - Required Steps (CONFIDENTIAL)*

Attachment III-1 *Southern California Edison Company's (U 338-E) 2019 Wildfire Mitigation Plan*

Attachment III-2 *California Public Utilities Commission's June 3, 2019 Guidance Decision On 2019 Wildfire Mitigation Plans Submitted Pursuant To Senate Bill 901*

Attachment III-3 *California Public Utilities Commission's June 4, 2019 Decision on Southern California Edison Company's 2019 Wildfire Mitigation Plan Pursuant To Senate Bill 901*

Attachment III-4 *SCE 2019 Wildfire Mitigation Plan Presentation*

SCE's Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Table of Contents (Continued)

Section	Page	Witness
Attachment III-5 *SCE Proposed Hybrid Overlaid with CPUC High Fire Threat Map*		
Attachment III-6 *Fire-Threat Maps & the High Fire-Threat District (HFTD) - HFTD Map - GIS Web Viewer Applet*		
Attachment III-7 *Memorandum of Understanding Between the California Public Utilities Commission and the California Department of Forestry and Fire Protection*		
Attachment IV-1 *Bradford Thompson, Appraisal Qualifications*		
Attachment IV-2 *Mason & Mason Appraisal Review of an Appraisal Report Prepared by Jones, Roach, and Caringella, Inc., 102.43 Acres Essentially Vacant Land, Anthony P. Vernola Trust Property, SEC of Bellegrave Avenue & I-15, Jurupa Valley, California*		
Attachment IV-3 *Mason & Mason Appraisal Review of an Appraisal Report Prepared by Jones, Roach, and Caringella, Inc., 64.67 Acres Essentially Vacant Land, Sky Country Property, Limonite Avenue, Jurupa Valley, California*		
Attachment IV-4 *Mason & Mason Appraisal Review of an Appraisal Report Prepared by Jones, Roach, and Caringella, Inc., 21.92 Net Acres Vacant Land, Vernola Trust North Property, Limonite Avenue, Jurupa Valley, California*		
Attachment IV-5 *Mason & Mason Appraisal Review of an Appraisal Report Prepared by Curtis-Rosenthal, Inc., Lesso-Thoroughbred Farms Property, 12071 Bellegrave Avenue, Jurupa Valley, California*		
Attachment IV-6 *August 9, 2019 E-mail correspondence from B. Tilden Kim to Bradford Thompson*		
Attachment IV-7 *Anderson, O and Williamson, J and Wohl, A, The Effect of High-Voltage Overhead Transmission Lines on Property Values: A Review of the Literature Since 2010*		
Attachment IV-8 *Jackson, Pitts, and Norwood, The Effects of High Voltage Electric Transmission Lines on Commercial and Industrial Properties*		

SCE's Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Table of Contents (Continued)

Section	Page	Witness
Attachment IV-9 *Jackson, T and Pitts, J, The Effects of Transmission Lines on Property Values: A Literature Review*		
Attachment IV-10 *Mason & Mason, Real Estate Appraisers & Consultants, Revised 2004 to 2007 Proximity Study, Supplemental 2004 to 2008 Proximity Study, High Voltage Transmission Corridors (May 15, 2009)*		
Attachment IV-11 *Feb. 9, 2016 Correspondence from D. Cosgrove to J. Uchida*		
Attachment IV-12 *Agreement Addressing a "Hybrid" Alternative in the Riverside Transmission Reliability Project Proceeding between the so-called "VAP Parties," the City of Riverside, and Southern California Edison Co. (Aug. 1, 2016)*		
Attachment IV-13 *Photos of Overhead SCE Transmission Lines Near Commercial Developments*		
Attachment IV-14 *U.S. Census Website, Jurupa Valley Webpage*		
Attachment V-1 *Response of Sky Country Investments Co./East LLP to Question 3 of the First Data Request of the Southern California Edison Company*		
Attachment V-2 *Response of Sky Country Investments Co./East LLP to Third Data Request of the Southern California Edison Company*		
Attachment V-3 *SCE Cost Estimating Material Takeoff, Lennar Hybrid (Jan., 2016) (CONFIDENTIAL)*		
Attachment V-4 *SCE Cost Estimating Material Takeoff, Pats Ranch Road (Aug., 2015) (CONFIDENTIAL)*		
Attachment V-5 *SCE Response to Gateway Properties Parties Data Request Verbal 001 (5/14/19)*		
Attachment V-6 *SCE TRTP Segment 8, Chino Hills 500kV Underground Cable Project, Specification No. E-2012-65, XLPE Cable Systems (Furnish & Install), RFP Issue, 21-NOV-2012, Rev Bid 1, Table 1.1 - Lump Sum Price Quotation Form (Option A) (Circuit 1 with 2 cables per phase) Completed by Prysmian (CONFIDENTIAL)*		

SCE's Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Table of Contents (Continued)

Section	Page	Witness

Attachment V-7 *SCE Response to Gateway Properties Parties Multiple Data Requests (CONFIDENTIAL)*

Attachment V-8 *Gateway Properties Parties Data Request 14.4 and SCE Response Thereto*

Attachment V-9 *SCE Response to Gateway Properties Parties Data Request 14.3*

Attachment V-10 *TRTP Owners Agent Actual Costs vs. Total Direct Construction Costs (CONFIDENTIAL)*

Attachment V-11 *SCE Response to Gateway Properties Parties Data Request 2.4 (CONFIDENTIAL)*

Attachment VI-1 *NV5, Underground 220-kV Double Circuit Transmission Feasibility Study, Riverside Transmission Reliability Project (Sep't. 20, 2018)*

Attachment VI-2 *Pacific Gas & Electric Company, PG&E Jefferson-Martin 230 kV Transmission Project, WETS '07 Workshop (June 28, 2007)*

Attachment VI-3 *Vazquez, Chy, Rector & Grant, T&D World, Engineering a 500-kV Underground System (Apr. 28, 2017)*

Attachment VI-4 *SCE RTRP Hard Rock Trenching Risk Worksheet (CONFIDENTIAL)*

Attachment VI-5 *March 15, 2019 Correspondence from Roman Vazquez of SCE to Shaun Stone of IEUA*

Attachment VII-1 *Map Depicting RTRP Hybrid Route and Cal Enviro Screen 3.0 Scoring*

Attachment VII-2 *Map Depicting RTRP Hybrid Route, Low-Income Communities and Disadvantaged Communities*

Attachment VII-3 *2017 Jurupa Valley General Plan Figure 11-8*

Attachment VII-4 *Map Depicting Alternative Routes Referenced In 2013 FEIR and Cal Enviro Screen 3.0 Scoring*

SCE's Rebuttal Testimony Supporting Its Application for a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Table of Contents (Continued)

Section	Page	Witness
Attachment VII-5 *Map Depicting Alternative Routes Considered In Southern California Edison Company (U 338-E) And The City Of Riverside's Joint RTRP Lower Voltage And Other Design Alternatives Report and Cal Enviro Screen 3.0 Scoring*		
Attachment VII-6 *Photographs of SCE Transmission Lines Near Commercial, Industrial, Residential Developments*		
Attachment VII-7 *Map and List of Recent Residential Property Sales Above $500,000 In Jurupa Valley*		

I.

Introductory Statement

Responding to the direct testimony offered by various intervenors and served on Southern California Edison Company ("SCE") on June 24, 2019 and July 2, 2019 and consistent with the Assigned Commissioner's Scoping Memo and Ruling ("Scoping Memo") issued by Commissioner Liane M. Randolph on December 20, 2018, SCE hereby serves the following rebuttal testimony regarding:

1. The need for RTRP as justified by applicable electrical planning standards and criteria, as well as the unreasonableness of alternatives suggested in other testimony submitted in this proceeding, sponsored by Dana Cabbell;

2. SCE's strategies, programs and activities in place to proactively address and mitigate the threat of electrical infrastructure-associated ignitions that could lead to wildfires and the reasons why RTRP does not pose wildfire risks sufficient to warrant undergrounding the entire project, sponsored by Mustafa Ali;

3. The maximum prudent and reasonable cost of the Riverside Transmission Reliability Project (RTRP or Project) and the estimated cost of the Project alternatives, sponsored by Kathy Hidalgo;

4. Critical reviews of the various appraisals of real properties where RTRP facilities would be located, as well as considerations related to the purported impacts of overhead transmission lines on property values, sponsored by Bradford Thompson;

5. The estimated scopes of work required to construct RTRP and alternatives, sponsored by Roman Vazquez;

6. The reasons why concerns raised in other testimonies regarding purported environmental justice impacts associated with RTRP are overstated, especially considering that alternative designs and locations for RTRP could result in greater environmental justice impacts, sponsored by Gary Busteed.

This rebuttal testimony contains confidential information, both in the testimony itself and in several attachments. Therefore, two versions of this rebuttal have been created; 1) a Confidential

Version (which is being served on those parties who have executed a Nondisclosure Agreement with SCE), as well as Public Advocates Office and Administrative Law Judge Hallie Yacknin; and 2) a Public Version, which is being served on all testimony recipients. Confidential information has been redacted and/or omitted as warranted in the Public Version and designated in the Confidential Version.

II.

SCE's Rebuttal Testimony Regarding The Need For RTRP As Justified By Applicable Electrical Planning Criteria, The Unreasonableness Of System Alternatives Suggested In Other Testimony, And The Qualifications Of Dana Cabbell[1]

Q: Please state your name and business address for the record.

A: My name is Dana Cabbell, and my business address is 3 Innovation Way, Pomona, CA 91768.

Q: Briefly describe your education, work history and present responsibilities at SCE.

A: I graduated from California Polytechnic University, San Luis Obispo with a Bachelor of Science degree in Electrical Engineering in 1982. In 1989, I became a Registered Professional Electrical Engineer with the State of California.

I have worked for Southern California Edison Company ("SCE") for 36 years in the areas of transmission, and distribution planning. Presently, I am the Director of the Integrated System Strategy ("ISS") Group for SCE. In this position, I'm responsible for providing a holistic view of the long-range planning for SCE's transmission and distribution systems, allowing for well-informed, strategic decisions regarding grid investments, integration of renewable/energy storage resources, enabling grid modernization, and resiliency efforts.

Q: Please describe your role with respect to the RTRP.

A: As Director of the ISS Group, I lead a team of power system planners who perform the technical studies required to assess the future reliability/adequacy of SCE's electric grid. These technical studies also include evaluating service requests from SCE's wholesale customers, such as the one requested by Riverside to address its increase in customer demand, and to evaluate a second point of interconnection with the SCE transmission system.

Q: What is the purpose of your testimony in this proceeding?

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[1] This section addresses Scoping Memo Issues ## 6 ("*To the extent that the proposed project and/or project alternatives results in significant and unavoidable impacts, are there overriding considerations that nevertheless merit Commission approval of the proposed project or project alternative?*") and 7 ("*Does the proposed project serve a present or future public convenience and necessity? This issue directly overlaps issue 6, above.*").

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Rebuttal Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to: the need for RTRP given peak demand forecasting methodologies, applicable planning standards and criteria applicable and relevant to Riverside's unique radial system design through which RPU's customers are served; the unreasonableness of alternatives that would necessitate SCE to make unreasonable changes to its existing infrastructure or pursue costly alternatives that would only provide short-lived benefits; and the SCE and Riverside roles in the overall California electrical grid.

Q: Is your testimony being provided in response to any particular testimony served by any of the other parties to this proceeding?

A: Yes. I am responding in particular to portions of the *Prepared Testimony* provided by the Public Advocates Office served on June 24, 2019, specifically Chapter 2, "*The RTRP Is Not Justified According To Existing Transmission Planning Standards*" and Chapter 3, "*The Load Forecast Presented In Riverside's Testimony Differs From The Forecast Adopted For Transmission Planning By The CAISO, And Should Not Justify The RTRP*," which are sponsored by witness Ken Lewis. For brevity, I refer to these collectively as the "*Lewis Testimony*" throughout the balance of this rebuttal testimony.

Q: Can you please respond to the statements at pages (3-1 – 3-12) of the Lewis Testimony stating that when considering the need for RTRP, the parties and the CPUC should be using peak load forecast data compiled by the California Energy Commission ("CEC") and detailed in its Integrated Energy Policy Report ("IEPR"), not Riverside's own peak demand forecast data?

A: I am informed that RPU's rebuttal testimony will be speaking to this in greater detail, but from a forecasting perspective, a threshold concern I have is that the *Lewis Testimony* does not account for the differences resulting from the RPU completed non-coincident demand forecast and the coincident demand forecast reflected in the CEC's IEPR.[2] This is an "apples to oranges" comparison, which necessarily causes the CEC IEPR data to reflect lower peak demand allocated to Riverside, because local Riverside customer demand peaks at a different time than the overall California Independent System Operator ("CAISO") system. When considering the need for a project serving a radial distribution system (like Riverside's here), the key question is whether there would be sufficient capacity available to meet that system's own peak demand, which for RPU is considerably higher than the peak reflected in the CEC IEPR forecast. While my testimony below goes into more detail regarding some of the other issues raised in the *Lewis Testimony*, the use of the CEC IEPR forecast data for the specific purpose of planning for adequate capacity to serve Riverside peak load represents a fundamental concern.

Q: Can you please respond to the statements at pages (2-1 – 2-11) of the Lewis Testimony regarding the standards and criteria that should govern the assessment of the need for RTRP?

A: The *Lewis Testimony* suggests that North American Electric Reliability Corporation ("NERC") and CAISO Reliability Standards should govern the analysis of whether RTRP is needed. It is my professional opinion that neither NERC nor CAISO standards are appropriate, for several reasons, including: a) by their own terms, the NERC reliability standards are applicable to Bulk Electric System ("BES") facilities, not to a 66 kV radial local distribution system like the system serving Riverside; and b) the *Lewis Testimony* focuses largely on contingency events, not "base case" conditions where future demand is forecast to exceed available capacity even when there is no contingency. In addition, if these reliability standards were applicable to the current situation at Vista Substation, base case conditions and contingency events that could impact service to Riverside *do* in fact justify construction of RTRP consistent with those standards.

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[2] As applied here, "coincidence" refers to the amount of demand at the exact moment when the CAISO system as a whole experiences its peak, as opposed to the various and multiple times when each CAISO participant might experience its own respective peak demand.

A. NERC And CAISO Reliability Standards Are Not Applicable When Assessing Local Radial Distribution System Needs

First, the NERC reliability standards referenced in the *Lewis Testimony* apply only to components of the BES. NERC itself has designated the BES, with limited exceptions not applicable here, to consist of networked facilities that operate at voltages *above 100 kV*, not local radial distribution systems.[3] In 2012, NERC confirmed the types of facilities that it considers to be the BES, removing language allowing for regional discretion and instead establishing a bright line threshold that includes all facilities operated at or above 100 kV.[4]

Pursuant to that definition, the 66 kV subtransmission components at Vista Substation, including the 220/66 kV transformers, 66 kV bus and 66 kV lines, are not part of the BES, but are defined to be local radial distribution facilities because they operate at below 100 kV and locally serve RPU in a radial manner. As confirmed in a FERC *Order On Local Distribution Determination* regarding SCE facilities:

> In Order No. 773, the Commission approved modifications to the North American Electric Reliability Corporation's (NERC) definition of 'bulk electric system.' . . . The revised definition has a bright-line threshold that includes all facilities operated at or above 100 kV and specific categories of facilities and configurations as inclusions and exclusions to the definition. The Commission indicated in Order No. 773 that the Application of the core definition and the exclusions should serve to

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[3] *See* Attachment II-1 (a NERC guidance memorandum dated April 10, 2012 that, in discussing NERC definitions, also confirms the applicability of NERC reliability standards to the BES only), at p. 3.

[4] *See* Attachment II-2, *BES Definition Implementation Guidance* (August 25, 2014) (a NERC memorandum providing guidance as to how transmission entities should implement BES interpretations), at p. 4. NERC's current definition of BES provides: "Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy." See *NERC Glossary of Terms Used in NERC Reliability Standards*, (updated May 13, 2019), at p. 6, available at: https://www.nerc.com/files/glossary_of_terms.pdf; *see also*, FERC Order No. 773, 141 FERC ¶ 61,236, at p. 12.

exclude most facilities used in local distribution from the bulk electric system.[5]

Like most of SCE's subtransmission assets, the Vista Substation components dedicated to serving Riverside are not designated as BES since they operate as radial facilities and operate at the 66 kV level (*i.e.*, below the 100 kV BES threshold designated by NERC). In fact, for many years, SCE has defined its local radial distribution systems, with limited exceptions, to consist of facilities downstream of a single connection point to the BES; for SCE, that includes 220/115 kV and 220/66 kV substations (known as "A" stations). In reviewing SCE's transmission and distribution systems, FERC confirmed that because of the radial (as opposed to networked) nature of SCE's system, even most of SCE's *115 kV* systems were "used in local distribution of electric energy."[6] Aside from the fact that the 66 kV facilities at Vista Substation are below the FERC-established 100 kV threshold, the same factors identified in the FERC Order regarding SCE's 115 kV facilities apply to an even greater extent to the Vista 66 kV Substation facilities. Therefore, to the best of my knowledge, it has been SCE's consistent position that NERC reliability standards applicable to the BES do <u>not</u> govern the assessment of whether system upgrades are necessary to support a 220/66 kV substation serving local radial distribution load, but rather, as discussed further below, SCE would assess the need for a new project against its own planning criteria.[7] Attached hereto as Attachment II-4 is an excerpt from section 1.0 of SCE's *Transmission Planning Criteria*, which states, "Planning for facilities not identified as BES are provided in the Subtransmission Planning Criteria and Guidelines."

The *Lewis Testimony* also asserts that under NERC and CAISO reliability standards applicable to BES facilities, the threat of a cascading outage should be a determining factor when considering the need for a new project. The threat of a cascading outage is not an appropriate system performance

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[5] *See* Attachment II-3, 153 FERC ¶ 61,384 (issued December 31, 2015), at p. 2.

[6] *Id.*, at pp. 9-13.

[7] While RTRP is designed to address the insufficiency of a radial substation facility, RTRP itself will be part of BES and integrated as a networked facility on the CAISO grid once constructed.

metric for the current situation, because as a radial system, even the contingency event described by the *Lewis Testimony* at pages 2-5 – 2-8 (*i.e.,* the simultaneous outage of a Vista Substation transformer and outage of an RPU generating unit) could not impact BES facilities, with the exception of the high-side 220 kV circuit breaker at Vista Substation. In this regard, to the extent that the *Lewis Testimony* suggests that under NERC reliability standards, RTRP is not necessary because it would not serve to prevent a cascading event on the bulk electric system,[8] that consideration is inapposite given that with the exception of the 220 kV lines, 220 kV bus, and 220 kV circuit breakers the remaining facilities (including those which serve Riverside) at Vista Substation are not part of the BES.[9]

B. <u>RTRP Is An Appropriate Solution For Meeting RPU System Needs Even Under NERC And CAISO Reliability Standards</u>

If the NERC and CAISO reliability standards for determining the need for a new transmission project were to govern (which they do not), the *Lewis Testimony* ignores the significant impacts to Riverside's system that an outage at Vista Substation would cause, requiring mitigation to avoid load shedding. For instance, the CAISO standards specifically acknowledge that infrastructure upgrades are appropriate where contingency events would risk dropping load, especially in dense urban areas:

> For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.[10]

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[8] *See* Lewis Testimony, at pp. 2-2 – 2-3.

[9] Indeed, any approach that focuses on the threat of cascading outages would prejudicially understate the need for new infrastructure to support any radial system that has only one power source, even though the loss of that source would lead to an outage of all customers without a backup delivery of power.

[10] *See California ISO Planning Standards* [the "*CAISO Standards*"], effective September 6, 2018, at § II.6.1. A true and correct copy of the CAISO Standards is attached hereto as Attachment II-5.

The *CAISO Standards* further explain that this provision is intended to avoid the need to drop load in high density urban load areas due to, among other reasons, high impacts to community essential services, ranging from hospitals and police and fire stations to traffic lights and building elevators.[11] Riverside is specifically identified as a high density urban load center in the *CAISO Standards*,[12] and as further detailed in Riverside's direct testimony served on March 1, 2019, Riverside is home to many critical area services and facilities, including emergency responders, hospitals, and university and office buildings.

The *Lewis Testimony* also suggests (at p. 2-3:14-15) that outage risks from seismic or third-party events should be a factor in whether an infrastructure upgrade would be warranted, especially if service restoration times might be protracted. These factors are critical for Riverside, where a system outage caused due to infrastructure damage at Vista Substation could be extreme. Such an outage could be the result of an earthquake (an ever-present risk in Southern California), or nefarious action such as terrorism or cyber-attack. If such an event caused damage to one of the transformers at Vista Substation currently serving RPU's load, depending on circumstances such as weather, system operational needs and environmental conditions, SCE's substation construction and maintenance personnel have informed me that although a spare transformer itself may be available in short order, it could take up to 30 days, but possibly as long as six-to-eight weeks, to clean up the damaged substation; contain any contaminants; and transport, install and prepare a new transformer before it could be operational. During that time, other operational procedures likely would be implemented to accommodate some of RPU's customer load, but (as discussed further below in other portions of my testimony) even such operational strategies are limited. As a result, a substantial amount of load would be susceptible to outages until replacement equipment is operational.[13]

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[11] *See* CAISO Standards, at § VI.1.

[12] *See* CAISO Standards, at § VI.1.

[13] Of course, this situation would become catastrophic if *both* transformer banks serving RPU load were rendered inoperable. Such situations are not just theoretical; indeed, SCE has experienced an event at Moorpark Substation where overlapping failures of two transformers occurred. In addition, as I mentioned in my direct testimony,

(*Continued*)

Similarly, the *Lewis Testimony* glosses over the fact that even the *CAISO Standards* acknowledge that upgrades might be necessary where available back-ties are not sufficiently sized to provide certain load support in a contingency situation.[14] In fact, I believe the concerns regarding the sufficiency of available back-ties is actually even more acute for Riverside, because there are no back-ties to serve its system at all. Riverside is only connected to the SCE system *via* one source – the transformers on the "C" bus section at Vista Substation.

In summary, although the standards applicable to the BES do not govern an assessment of whether RTRP would be an appropriate way to accommodate RPU's service needs, there is a demonstrated need for RTRP under those standards as well.

Q: *If the NERC and CAISO reliability standards are not applicable, are there any criteria that do govern whether RTRP is needed?*

A: Yes. SCE maintains its own planning criteria for its subtransmission elements, and those criteria provide more appropriate guidance for evaluating the need for a new project like RTRP. Attached hereto in Attachment II-6 are relevant excerpts from SCE's *Subtransmission Planning Criteria and Guidelines* (the "*SCE Criteria*"). As shown in those excerpts, SCE has determined that, with limited exceptions, its radial system components should be designed in a manner such that load losses would not be experienced under either "Base Case" (N-0) or "Likely Contingency" (N-1) conditions, while also ensuring that equipment use would not exceed the Short Term Emergency Loading Limits for a duration longer than one hour ("STELL") or the Long Term Emergency Load Limits for a duration longer than 30 days ("LTELL").[15]

Continued from the previous page

Vista Substation itself suffered significant outages on July 3, 2005 and October 26, 2007 that resulted in the loss of SCE's ability to serve Riverside's load.

[14] *See* CAISO Standards, at § II.5.3.

[15] *See* Attachment II-6, at §§ 2.2.1, 2.3.2. – 2.3.2.2.B.

To ensure that those criteria are satisfied where load growth is occurring, SCE strives to design its system so as to maximize the capacity of existing facilities, take advantage of existing capacity of adjacent system components through system ties and load rolling, or add more transformation capacity at existing substations. If such methods are shown to be unavailable or insufficient, SCE then would consider construction of new grid facilities for adding additional capacity.

With respect to Riverside, there are no system ties available, because RPU operates as a publicly owned utility independent of SCE's system. In addition, there is no way to add more capacity at Vista Substation due to the lack of physical space available within the substation property to expand the existing 220 kV bus to allow for another 220/66 kV transformer to serve Riverside, and the substation property cannot be expanded due to existing physical and geographical limitations, as explained in SCE's response to Question 02 of Data Request Set Cal Advocates 004 (a true and correct copy of which is attached hereto as Attachment II-7). In addition to the details set forth in that data request response, Vista Substation is unique in SCE's system as it is the only A-substation with two low-side voltages (both 66 kV and 115 kV) being served through the 220 kV BES through 220/66 kV and 220/115 kV transformers. This configuration requires a substantial amount of equipment that has resulted in Vista Substation being unable to accommodate further capacity expansion.

In conclusion, I strongly disagree with the *Lewis Testimony*'s assertion that upgrades to SCE's subtransmission system components serving Riverside are unwarranted in the absence of the criteria listed on page 2-4 of the *Lewis Testimony*. This is particularly true given that the criteria identified by the *Lewis Testimony* ignore base case needs altogether. Additionally, the *Lewis Testimony* applies incorrect and inapplicable peak load forecast data. As explained further in my direct testimony served on March 1, 2019, RTRP was proposed to both: a) accommodate increasing load demand from RPU customers given the base case exceedance of Vista Substation's transformation capacity dedicated to RPU; and b) to provide additional capacity during N-1 conditions. The RTRP is the appropriate solution for achieving these objectives.

Q: ***Would you please respond to the statements in the Lewis Testimony suggesting that RTRP is not needed because SCE could instead implement system or operational solutions to address Riverside's capacity and redundancy needs?***

A: I disagree with the assertions in the *Lewis Testimony* (at p. 2-7:6-9) that suggest operational strategies may be sufficient to adequately cover RPU's needs instead of RTRP. For one thing, the strategies recommended in the *Lewis Testimony* address emergency situations only and would not work to remedy the projected base case exceedance of the Vista Substation transformers' capacity, which is forecast to continue to grow beyond the transformer capacity dedicated to serving RPU. In addition, the approaches suggested in the *Lewis Testimony* also suffer from other electrical shortcomings that undercut their effectiveness as contingency response strategies. I will address those suggestions here.

C. Transferring RPU Load To SCE's San Bernardino System Would Not Address Base Case Overload Conditions And Would Only Address Posited Contingency Events For A Limited Time.

One strategy identified in the *Lewis Testimony* for maintaining as much service to RPU as possible in the event of a contingency resulting in the loss of a Vista transformer bank would be for SCE to transfer a significant portion of RPU load – as much as **284** MVA – from SCE's Vista System to SCE's San Bernardino System. Theoretically, to perform this transfer, Riverside load would have to be split such that: a) some would be served from the remaining operational 220/66 kV transformer bank at Vista 66 kV Substation C-bus section on the West bus; and b) some would be served through a remaining connection to the Vista 66 kV Substation C-bus section on the East bus, but with power supplied via the 66 kV tie lines connected to the East bus of the C-section of Vista Substation from SCE's San Bernardino System. However, there are multiple flaws associated with this suggestion.

1. The *Lewis Testimony* Does Not Recognize Limitations On How Much Load Can Be Transferred.

At the outset, I would note that the statement that **284** MVA of load can be transferred to San Bernardino Substation through 66 kV tie lines is based on an oversimplified assumption that transfer capacity is based on maximum 66 kV tie line conductor ratings only. Conductor ratings are only one factor to be considered, and a technical analysis that considers power flow and voltage limitations reveals that a far smaller amount of load can be transferred. In fact, the analysis shows that the suggestion to transfer load from Vista Substation to San Bernardino 66kV System is unstainable and ineffective.

First, the *Lewis Testimony* (at p. 2-7:7-9) states that under emergency rating conditions, the 66 kV tie lines between Vista 66kV and San Bernardino 66kV systems can theoretically support a transfer of as much as **284** MVA during a contingency event. However, this represents maximum theoretical capacity of the two 66kV tie lines and is not reflective of actual load transfer capability. A detailed power flow study is required. A proper study in this regard would include necessary considerations such as system configuration, characteristics of the 66 kV lines, and the peak load values of the connected substations that would be transferred (not simply the summation of the emergency rating capacity of the tie lines). In reviewing this proposal, SCE performed such a power flow analysis and determined that a thermal overload on the subject tie lines would actually occur when **264** MVA is transferred to the San Bernardino System, given that the two lines are of different lengths, have different impedance characteristics, and do not evenly split the load between them.[16] Therefore, the maximum amount that theoretically could be transferred in this approach would be **264** MVA, not **284** MVA as identified by the *Lewis Testimony*.

Second, a proper assessment of transfer capability would also have to consider how actual substation loads would be transferred to new source lines. The *Lewis Testimony* presumes that **284** MVA of RPU load can be transferred as a complete amorphous block, but in reality, the load that would be transferred consists of the load *actually served* by the discrete individual substations within RPU's system that would be transferred. When selecting which discrete substations should be transferred under a scenario such as this, the options available to Riverside's system planners and field operations

[16] In fact, the 264 MVA theoretically available on these tie lines would only be available during contingency events lasting four hours or less (as discussed in more detail below). After four hours, the maximum rating of the lines would return to the lines' normal rating value, which, when also evaluated through a power flow study, yields a maximum transfer capability of actually **197** MVA.

personnel would be limited by the configuration of the existing network and the peak loads of each of the substations. In particular, consideration must be given to the configuration of the existing subtransmission lines, maintaining acceptable voltage, and reliability. Given the existing configuration and the load distribution characteristics of the Riverside subtransmission system, I have been informed that RPU expects that it would propose to transfer four of its internal substations (*i.e.,* University, La Colina, Springs. and Orangecrest) in this hypothetical scenario.[17] I have been further informed that together, these substations in 2019 would account for **177** MVA (and approximately 32,000 metered customers) of Riverside load.[18] I understand that these four substations were selected by Riverside based on several factors, including their projected loading values and the physical configuration of the Riverside system. Should a fifth substation be considered for transfer along with the identified four, the next in line would be Freeman Substation, which has a projected load of **88.4** MVA in 2019. When that 88.4 is added, the resulting transfer amount would be **265.4** MVA (**177 + 88.4 = 265.4**), which is greater than the maximum transfer capability of **264** MVA of the tie lines as determined by these power flow studies and described above. Since the actual transfer capability of the San Bernardino option is determined by several factors, but ultimately limited to the amount of load comprised of these four substations, the transfer capacity for use in this exercise is only really **177** MVA today and would only be 186 MVA in 2030, notwithstanding the assumption in the *Lewis Testimony* that **284** MVA of load could be transferred to the San Bernardino System. In short, the *Lewis Testimony* overstates the transfer capacity of this option by 107 MVA today and **98** MVA in 2030. (**284 – 177 = 107 and 284 – 186 = 98**.)

This limitation restricts SCE's ability to transfer Riverside load to the San Bernardino System tie lines, and consequently SCE's ability to serve Riverside as a whole. If a Riverside-dedicated 220/66 kV transformer bank fails, assuming there is no tie to the transformer banks serving SCE load from the A-

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[17] The Springs Substation is a load distribution substation and a generation facility.

[18] Riverside's peak load projections for the four substations subject to transfer increase over time and in 2030 they total **186** MVA and in 2038 they total **197** MVA.

section of Vista Substation (a scenario which I will discuss further below), **480** MVA of capacity would remain available to serve the remaining Riverside load that was not transferred to the San Bernardino System. That would be composed of: **336** MVA using the LTELL of the remaining operational bank at Vista Substation C-section bus dedicated to serving Riverside, and **144** MVA from the operation of three of the four Riverside RERC generation facilities when considering a single generation unit is out-of-service.[19] (**336 + 144 = 480**).[20] Therefore, the key question is whether enough Riverside load can be transferred to the San Bernardino System to keep demand on the remaining resources below that **480** MVA limit. However, according to Riverside's own Integrated Resource Plan ("IRP") forecast, Riverside projects that even this year (2019), its service area's peak demand during heat storm conditions will be **659** MVA, with the four 66 kV substations listed above accounting for **177** MVA of that total. That means that the burden on the remaining Vista Substation C-section transformer bank and the assumed three operational RERC facilities would be **482** MVA. (**659 – 177 = 482**.) Thus, even this year, the hypothetical transfer of Riverside load to the San Bernardino System during peak load conditions following an unplanned outage of one of the two Riverside-dedicated transformers at Vista Substation with one RERC unit offline would not occur without load shedding: **2** MVA of load is

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[19] Riverside's RERC generation consists of four individual generating units that produce **48** MVA each, for a total of **192** MVA. Riverside's Springs generation consists of four individual generating units that produce **9** MVA each, for a total of **36** MVA. Combined, the theoretical maximum total amount of Riverside generation is **228** MVA. (**192 + 36 = 228**) Note that generation resources are often referenced in megawatts (MW), not MVA. For simplicity and consistency in units, this rebuttal testimony treats MW and MVA as equivalent units and uses MVA throughout.

[20] Similar to the *Lewis Testimony*'s erroneous calculation of the tie line's transfer capacity, it also misstates the amount of *generation resources* that would remain available to serve Riverside load from Vista Substation following the transfer of four substations to the SB system. Existing generation resources in Riverside account for a total of **228** available MVA. The *Lewis Testimony* states that with one **48** MVA RERC generation unit out and with the loss of a Vista transformer bank serving Riverside, **180** MVA of generation would be available to serve load that is not transferred under this scenario. (*Lewis Testimony*, at fn. 36.) That is incorrect. In reality there would only be **144** MVA available, because **36** MVA of Riverside's generation resources are connected to Springs Substation – the same Springs Substation that would be part of the San Bernardino transfer. Therefore, the transfer of the Springs Substation away from the Vista C-section to the San Bernardino tie lines would mean that the **36** MVA of generation resources associated with Springs would no longer be connected to the Vista Substation C-section. As a result, the balance of generation resources that would remain available to serve Riverside from Vista Substation would only be **144** MVA. (**228 – 48 – 36 = 144**.)

already at risk in 2019. The situation progressively worsens over time. For example, Riverside's peak load is projected to reach **693** MVA by 2030, so the amount of load at risk of being served at that time would be **27** MVA. [**693** (Riverside peak load) – **336** (LTELL of remaining Vista C-section transformer) – **186** (transferred to San Bernardino System) – **144** (remaining RERC generation) = **27**.] For 2038 (the last year for which Riverside's 2018 IRP provides peak demand forecast data), Riverside's peak load is forecast to be **733.6** MVA, meaning the deficiency can be expected to reach **67.6** MVA. (**733.6 – 336 – 197 – 144 = 67.6**.)

Additionally, this hypothetical proposal presumes that the RERC generation facilities would remain fully operational through 2038 (*i.e.*, after approximately 30 years of operation), which as I explain elsewhere in this rebuttal, is unlikely at best.[21] However, SCE notes that a comprehensive assessment of this proposal should also consider what solution would be available once those generators cease operation.[22] It is reasonable to expect, and indeed Riverside has indicated, that its generation facilities cannot be relied upon to operate indefinitely. If the operation of the RERC units were to cease at any time through the balance of Riverside's IRP forecast period, the magnitude of the deficiency would skyrocket, with the result that more than **200** MVA of Riverside load would be at risk by 2038. (**8.6 + 192 = 200.6**.)

The *Lewis Testimony* also does not account for the fact that a hypothetical solution involving load transfers to San Bernardino tie lines would be available for only four hours per day. SCE limits the operation of its subtransmission lines above their normal ratings during emergency conditions to four consecutive hours to prevent damage or unsafe conditions, regardless of which substation loads are

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[21] Even with all four RERC units online (producing 192 MVA) a capacity deficit of **8.6** MVA would still remain in 2038. [**733.6** (Riverside peak load) **– 336** (LTELL of remaining transformer) – **197** (transferred to San Bernardino) – **192** (RERC generation) = **8.6**.]

[22] Of course, as I discuss further in footnotes 29 and 39 below, there are a number of reasons why relying on the continued operation of Riverside's generation resources through 2033 may not even be appropriate in the first place.

proposed to be transferred.[23] In other words, although there purportedly *could be* as much as **264** MVA of capacity available on those lines to support Riverside load, any loading value above the normal condition rating would only be available for a four-hour period. As noted above, a major contingency event during peak load conditions could compromise service to Riverside for significantly longer than four hours, thus rendering this solution ineffective after that four-hour duration, when the lines must be returned to their normal condition loading limits. The maximum amount of power through 2038 that could be transferred using these two tie lines based on the four substations listed above is **197** MVA for any given four-hour period of time (before load reductions would have to occur to bring the line loadings back to within normal condition limits). Therefore, this option is unworkable as a solution for either: a) any event during peak conditions lasting longer than four hours; or b) base case loading conditions given projected growth.

2. The *Lewis Testimony* Does Not Recognize The Reliability Concerns That A Transfer Of Some Riverside Load Would Create.

Separate from the *Lewis Testimony's* overstatement of the actual transfers that could occur and the appropriate generation resources that would remain on the Vista C-section, it also does not acknowledge the reduction in overall reliability that a transfer of some Riverside load could cause. In order to transfer a portion of some of RPU's load to the San Bernardino System, the Vista Substation C-section double-bus, double-breaker switchrack would need to be split into two bus segments (East and West) to isolate the loads between the Vista and San Bernardino Systems. This would result in some RPU load served from the East bus via the San Bernardino ties, while some would remain connected to the West bus and served from the Vista System. This split would be required so that the portion of load transferred to the San Bernardino System would be isolated to avoid paralleling SCE's Vista and San Bernardino Systems. This leads to several negative consequences.

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[23] The emergency protocol for subtransmission lines is set at four hours to prevent sag that develops in the lines due to overloading. Too much current, even short in duration, can cause lines to sag below their design height, so lengthy (*i.e.*, longer than 4 hours) operations at emergency levels could subject lines to extreme sagging and potential collapse or other failure and safety concerns.

First, with respect to Riverside load, contrary to how RTRP would provide an additional source of power, Riverside's customers would lose redundancy under the San Bernardino transfer approach. This is because under the existing configuration, Riverside is connected to both the East segment and the West segment of the same C bus section, so they enjoy the benefits of reliability provided by a double-bus double-breaker configuration. Under normal conditions, if one bus segment were to fail, Riverside would have the other bus segment as a redundant source to serve the load. However, once those bus segments are split and isolated, all of Riverside's customers would only be connected to the single bus segment allocated to serving them pursuant to the split. Those customers would have no redundant source of power, and if their bus segment or the source serving it were to experience an outage (creating an N-1-1 contingency[24]), they would lose all service until the contingency event is remedied. In other words, even a single subsequent fault – *i.e.,* on the remaining transformer or either the East bus segment or the West bus segment of the Vista C-section – would take out multiple 66 kV lines serving Riverside load, with no secondary source of supply to support them.[25] Any resulting outage could be lengthy if substantial repairs were required or the installation of a replacement transformer were necessary.

Similar reliability concerns would impact SCE's customers served from the San Bernardino System via the tie-lines that would be used as a source of power to serve Riverside's customers on the C-section East bus of Vista Substation. To maximize the available capacity on the tie-lines to the San Bernardino System, the normal configuration of the tie-lines from San Bernardino System would need to be temporarily modified by removing some of SCE's customers from the tie lines and offloading them to San Bernardino subtransmission lines for the duration of the emergency condition. As a result, those customers would lose a redundant source of power, thus reducing reliability of service to them during that time. Among those SCE customers at increased risk would be Loma Linda University Medical Center, which, according to its website, is the largest and only Level 1 trauma center in San Bernardino,

[24] An N-1-1 contingency is typically characterized as a single contingency event followed by second subsequent contingency event.

[25] Single fault events such as these occur far more frequently and are far more likely to occur than N-2 (double contingency) events.

Riverside, Inyo, and Mono Counties, and with a total of 507 beds, it sees over 16,000 inpatients and about 470,000 outpatient visits a year.[26]

In addition to the capacity and reliability issues identified above, I also have concerns about the ability of SCE and Riverside equipment to handle faults that might occur on either or both of the systems at the time a transfer is in effect. The relays currently in place at Vista Substation are configured to accommodate faults on the Vista 66 kV system (and I presume Riverside's own equipment is similarly configured). However, line loadings and short circuit duty ("SCD") values when connected to the San Bernardino System are almost certainly different from those loads and values present when the lines are provided power from the Vista System. It is unknown to me in the absence of a wholesale re-examination of the existing equipment whether the subtransmission relays and other protection equipment would be able to detect fault conditions on the transfer configuration given the change in loading and SCD characteristics. If it cannot, a significant infrastructure replacement effort may be required just to accommodate this contingency transfer arrangement, without any long-term base case benefits.

Even if the protection relaying equipment is capable of adequately detecting and clearing fault conditions, if a contingency event were to occur that necessitated a transfer of some Riverside load to the San Bernardino System, all of that load would likely be without service for some time while the transfer is implemented. A transfer would involve a number of steps. First, as illustrated on Page 2 of Attachment II-8, upon an unplanned outage of either transformer dedicated to serving Riverside load from the Vista C-section, SCE would open (*i.e.*, disconnect or disengage) circuit breakers ("CBs") at Vista Substation to drop the four Riverside substations (accounting for **186** MVA in 2030 and approximately 32,000 metered customers) that would be transferred. SCE would then separate the East and West bus segments of the Vista C-section by opening all of the CBs connected to the East bus, as shown on page 3 of Attachment II-8. RPU would then have to open or close (*i.e.*, connect or engage)

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[26] *See* Loma Linda University Health website, Location Search webpage, available here: https://lluh.org/locations/loma-linda-university-medical-center (last checked August 15, 2019).

numerous CBs and switches and adjust relay settings to prepare for the transfer, and inform SCE when that activity has been completed. SCE would then adjust its own protection equipment and transfer load off the San Bernardino tie lines as required and then close the CBs connecting the tie lines to the East bus of the Vista C-section, as shown on page 4 of Attachment II-8. Only then would SCE be able to close the CBs of the two 66 kV lines (which serve the four Riverside Substations that were initially dropped) to the East bus segment restoring service to the Riverside load, as illustrated on page 5 of Attachment II-8.

This is often referred to as a "drop and pickup" scenario, and it could take minutes to hours depending on a range of factors. During that time, load would be interrupted, while all of the necessary configurations and relay settings are adjusted in real time.[27] In contrast, RTRP would negate the need to perform such activities which include intentionally dropping and picking up customers and thus, SCE believes RTRP would provide a far more appropriate solution.

D. <u>Revising SOB 32 To Allow Paralleling Of Three Vista Substation Transformers Would Reduce Reliability For Customers Served Out Of Vista Substation And Would Require SCE To Utilize Equipment In An Inefficient And Unreasonable Manner</u>.

Another suggestion in the *Lewis Testimony* that should be discarded is a suggestion that SCE should utilize other transformers at Vista Substation to support Riverside load during contingency events. This suggestion is also unreasonable.

As noted in the *Lewis Testimony*, in order to establish a standard operating procedure to be followed in the event of a likely contingency that results in a transformer outage at a substation like Vista, SCE has adopted *System Operating Bulletin 32: Loss of an A/AA Bank Overload Protection* ("SOB 32"). As applied to Vista Substation, SOB 32's instructions generally state that if one of the two RPU-serving transformers connected at Vista's C-section bus should experience an unplanned outage, SCE's grid operators should first open the circuit breakers connecting one of the two transformers

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[27] Another "drop and pickup" scenario would also occur once the contingency has been rectified and the multiple systems were ready to be restored to their previous operational configuration.

serving the A-section of the Vista 66 kV bus. Next, they would close (*i.e.,* connect and engage) bus tie connections between the Vista A-section and Vista C-section so that the one A-section transformer which typically only serves load from SCE and City of Colton could be used along with the one remaining C-section transformer to serve some of the RPU load. In other words, RPU load, along with SCE's A-section load and the City of Colton load, would be served by *two* transformers – one on the A-section and one on the C-section, which would be tied together to operate electrically in parallel. The other A-section transformer bank would have to be removed from service because the short-circuit current from *three* transformers operating in parallel on the combined bus would exceed the ability of substation equipment to safely accommodate it.[28] The resulting transformer LTELL capacity at Vista Substation with the A and C sections paralleled would be **658** MVA, and the resulting STELL would be **877** MVA.

While this maneuver would be helpful to accommodate more of Riverside's load than could be accommodated without performing the operating procedure, it would still not provide enough capacity to accommodate all of Riverside's forecast demand while also serving all of SCE's A-section load. According to Riverside's direct testimony and as referenced in the *Lewis Testimony*, RPU's 1-in-10 gross peak demand (without Riverside generation) is forecast to be **675.9** MVA in 2030. (*Riverside Public Utilities' Opening Testimony*, at Table 1-3; *Lewis Testimony,* at fn. 38.) SCE's peak projected heat storm load forecast for the period of 2019-2028 for the Vista A-section is **275** MVA.[29] Thus, the total load (prior to consideration of the Riverside generation) to be served out of the paralleled and combined Vista A+C bus is forecast to be at least **950.9** MVA (**675.9 + 275 = 950.9**) by 2030. However, as stated above, the LTELL rating of the two transformers that would remain operational under this scenario would only be **658** MVA. This would result in a total of **292.9** MVA of load <u>above</u>

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[28] In other words, one of the fully operational transformer banks serving the A bus (likely bank 3A) must be taken out, and thus would not be available either to continue serving SCE and Colton load, or to pick up additional RPU load.

[29] SCE typically only produces 10-year forecasts and the current forecast covers only through 2028. While demand is likely to be slightly higher in 2030, SCE is using the 2028 value of **275** MVA for this assessment.

the LTELL ratings of the two transformers serving the connected A and C-sections. (**950.9 – 658 = 292.9**.)

Other theoretical mechanisms implemented to reduce Riverside's demand on the two transformer banks connected in this scenario would still not completely account for all of Riverside's projected load. As discussed above, the maximum generation resources of Riverside total 228 MVA, and with one unit offline, the maximum available generation resources would total **180** MVA. (**228 – 48 = 180**.) Thus, the amount of load above the LTELL of two transformers and with **180** MVA of Riverside generation is **112.9** MVA in 2030. (**292.9 – 180 = 112.9**.) Therefore, **112.9** MVA would have to be shed or transferred out of Vista Substation.[30] Similarly, SCE has determined that through the use of existing system ties between the Vista A-section and the Mira Loma 66 kV System, up to approximately another **55** MVA could be transferred away to other systems to reduce the burden on the combined Vista A+C section. Yet even with the combination of three RERC generation units on line and the transfer of 55 MVA to other SCE sources, there would still be an exceedance of the LTELL capacity limit in 2030 of **57.9** MVA. (**112.9 – 55 = 57.9**.) In other words, because of SCD considerations (which would result from more than two transformers operating in parallel along with the Riverside generation) and the resulting need to remove from service one of the A-section transformers (to limit to SCD to acceptable levels), the load serving capacity that can be collectively obtained by paralleling the Vista A and C bus sections, even assuming 180 MVA of generation and exhausting existing load transfer options, is still well below what is needed to meet the load requirements of the customers served from Vista Substation.

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[30] This hypothetical exercise is premised on all but one of RPU's generating units producing power, for a total of **180** MVA. However, as stated above, there are a number of reasons why SCE does not consider RPU's generation assets to be dependable for planning purposes. In addition, RPU's ability to operate its generation is constrained by air district hours limitations, and in the event a contingency situation were to arise and this operation were to be implemented during a period when RPU had already exhausted its available hours credits, operating that generation may not be possible or practical. In addition, as the equipment ages it becomes less reliable, and I believe that RPU has already identified the projected lifespan of some of its generator units is a real issue affecting long-term viability of those units. In addition, I also note that continued reliance on fossil fuel burning generation units would not be consistent with general policy goals, including the State of California's renewables policy standards which call for significant reductions in greenhouse gas emissions over the coming decades.

To address the SCD concern and eliminate the need to remove from service one of the A-section transformers, the *Lewis Testimony* suggests that SCE should modify the terms of SOB 32 such that, if one of the Riverside-dedicated transformer banks were to fail, *all three* remaining transformers at Vista Substation (*i.e.*, both of the operational transformer banks connected to the Vista A-section, along with the sole functioning transformer on the C-section) could be operated in parallel.[31] Theoretically, this could increase the available capacity based on LTELL ratings to **997** MVA, which is the combined LTELL of the three remaining transformers operating electrically in parallel.

As the *Lewis Testimony* recognizes (at 2-9:22 – 2-10:2), using all *three* remaining transformers at Vista Substation in parallel would result in short-circuit current values that exceed the SCD rating of the 46 CBs installed at the 66 kV bus at Vista Substation, as well as the rated capability of the substation's ground grid. The 66 kV CBs at Vista Substation have a maximum SCD rating of 40 kA (40,000 amps), which, to the extent of my knowledge, is consistent with the maximum CB SCD rating available in the industry at this voltage.[32] Based on SCE's analysis, with three transformers operating in parallel, the SCD value at Vista Substation would be more than 42 kA, which would be above these CBs' 40 kA rating. To overcome the SCD issues, the *Lewis Testimony* further suggests that series reactors could be installed between the A and C sections of the Vista Substation 66 kV bus to reduce the amount of SCD that could occur during a faulted condition on the facilities served from the C-section without compromising the Vista Substation C-section CBs. (*See Lewis Testimony*, at 2-9:2-5, 9-11.)[33]

While in theory the installation of series reactors *could* assist in reducing the SCD to acceptable levels when three transformer banks at Vista Substation are operated in parallel, the *Lewis Testimony* ignores the fact that there are a number of other problems that this suggestion would create. For

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[31] *Lewis Testimony*, at 2-9:17 – 2-10:13.

[32] In other words, they are designed to operate properly when short circuit current flow is 40 kA or less during fault conditions, but current flow greater than 40 kA may cause the circuit breaker to be unable to interrupt the fault. This would result in unsafe conditions and likely damage the CBs and perhaps other equipment.

[33] A series reactor is a device that operates to reduce current flow (in this case short-circuit current) to levels that can be adequately handled by existing equipment.

instance, to implement the recommendation from the *Lewis Testimony* which is proposed to address expected N-1 conditions, Vista Substation's transformer banks would have to be consistently run above their PLL ratings (but below the LTELL rating) to avoid shedding load until the contingency event is remedied.[34] As stated above, the combined load demand at Vista Substation is forecast to be (at least) **950.9** MVA (without Riverside generation) by year 2030 (accounting for both RPU and SCE/Colton load), and the LTELL of the remaining three transformers is **997** MVA, which is greater than the forecast demand of **950.9** MVA. However, that maximum LTELL only applies for a limited duration per day and over a limited number of days (*i.e.*, no longer than 30 days), so any longer duration would require SCE to either: a) consistently operate equipment above PLL ratings (which would violate SCE's internal operating criteria, significantly increase the loss-of-life of the transformers, and potentially increase the risk of failure); or b) shed load until loading levels are at or below PLL ratings.[35]

Consistently operating substation equipment at levels above its PLL is not a reliable, standard, or efficient way to operate the system. When operated above planned loading levels, equipment functionality tends to degrade at a faster rate, shortening the expected useful life of that equipment, and accelerating the need to replace it with new components.[36] Constantly relying on that practice to accommodate demand for potentially lengthy periods of time would therefore hasten the need to replace the transformers at Vista Substation, which can be expensive (as each transformer costs several million dollars to replace), would jeopardize reliability (replacement activities themselves could require other

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[34] The PLL is the loading level established by SCE's apparatus engineers that incorporates such things as manufacturer equipment specification data, loss-of-life calculations, and loading profiles. This data is used to establish a balance between safe operational limits and economics considering loss of life for transformers operating during normal conditions.

[35] Note that the 30-day LTELL limit does not contemplate constant operation of facilities at LTELL levels during that 30-day period, but rather it is premised on fluctuations in use over that time to preserve equipment quality. (*See* footnote 35, below.)

[36] Although the LTELL represents a maximum amount that could be achieved during contingency events, it is also worth noting that the LTELL amount presumes that loading levels would cycle throughout daily usage. In other words, the LTELL presumes that demand on substation apparatus might peak at the LTELL level but would lessen at certain times of each day over that 30-day period. In the event that load becomes steadier and more constant than what the LTELL presumes, the degradation effects on substation equipment would be even further hastened.

contingency operations and or outages while work proceeds in the substation), and potentially result in safety hazards to personnel and other adjacent equipment should there be an unexpected failure due to continuous operation at higher than planned for values and durations.

This concern is manifestly problematic during contingency events that occur during peak load conditions and which could last longer than 30 days (which, as I mentioned above, could result from a catastrophic event causing significant damage to the substation). Even worse, the situation would be more critical if a second and subsequent contingency (N-1-1) event were to occur that resulted, for example, in the loss of another transformer bank at Vista Substation. Then, there would be only two operating transformers, which would operate at their highest allowed levels, with the balance of the overload being addressed through involuntary load shedding, while SCE attempts to accommodate the 292.9 MVA of load at risk (*see* above).

While the *Lewis Testimony* focuses on the use of the SOB 32 operating procedure during N-1 conditions, should this procedure also be considered as a potential solution for *normal base case* conditions, it would similarly fail to adequately address the electrical needs of the area. Normal base case loading values occur with all facilities in-service and normal condition ratings apply (*i.e.*, PLL).[37] Under normal conditions (all facilities in-service), the maximum PLL of three transformers at Vista Substation that hypothetically would be operational during this scenario is only **868** MVA. Therefore, paralleling three transformers as suggested by the *Lewis Testimony* would not even be a workable solution for base case conditions projected *this year* without dependable generation, because the 2019 combined peak load at Vista Substation is forecast to be **914.3** MVA. [**644.3** (from Riverside customers without Riverside generation) + **270** (from SCE/Colton customers) = **914.3**.][38] Compared against the PLL of three transformers (which is only **868** MVA), that would leave **46.3** MVA of load at risk of not being served. (**914.3 – 868 = 46.3**.) Therefore, even with series reactors in operation to address SCD

[37] The facilities could not use the LTELL ratings under normal conditions, as the LTELL ratings are reserved only for emergency contingency conditions.

[38] *Riverside Public Utilities' Opening Testimony*, at Table 1-3.

concerns, this suggestion would not be a workable solution to address base case normal operating conditions. To meet that higher demand, SCE would have to operate the transformer banks at Vista Substation at levels significantly above their PLL values (leading to the same equipment concerns I raised above) in the absence of involuntary load shedding.[39]

As noted in the *Lewis Testimony*, other ways to reduce the loading at Vista Substation could include relying on RPU generation and transferring some of SCE's load away from the Vista system to the Mira Loma System. However, as I stated above, relying on RPU's generators as a constant source of capacity is not practical in either the short-term or the long-term. In addition, although **55** MW of SCE load (in particular, load served out of SCE's Glen Avon Substation) could be transferred to the Mira Loma System, that would reduce reliability for all of the customers served out of Glen Avon. Glen Avon is currently served by two 66 kV lines from the Vista A-section, with a third line that operates with an open circuit breaker functioning as a system tie-line between the Mira Loma System and the Vista System. Transferring Glen Avon from the Vista System results in it being serving by a single line, meaning that if a likely contingency event were to remove that line from service, the entire Glen Avon Substation would be without service, rendering over 10,000 SCE metered customers without any source of power. The transfer of Glen Avon Substation to the Mira Loma System in this type of situation would thus unnecessarily subject Glen Avon Substation's customers to reduced reliability, just to help offset Riverside's capacity issues and existing reliance on just one source of power. This is an example of taking Riverside's electrical system issues and casting those problems onto other customers, rather than addressing them a comprehensive and long-term solution (*e.g.,* RTRP).

Another issue that this scenario would create is the fact that operating the Vista A and C bus sections in parallel would produce a common 66 kV bus for which system events (*e.g.,* faulted conditions or voltage fluctuations) on either the RPU system or the SCE system would be experienced

[39] As was the case with the suggestion to transfer load to the San Bernardino System, the situation in this scenario also worsens over time. For example, in 2030, total load on the Vista A and C sections is projected to be **950.0** MVA. Given that the three operating transformers have a PLL of **868** MVA, there would be **82.9** MVA of load at risk in 2030, even under base case conditions. (**950.9 – 868 = 82.9**.)

across both systems. This could reduce reliability for all customers served out of Vista Substation (SCE's – including load from the City of Colton – and RPU's), thereby subjecting each system's customers to contingency events from the other system, rather than being isolated and protected as they are today and as they would be if RTRP were constructed. To that end, I actually believe this suggestion would be inconsistent with one of the primary objectives of RTRP in the first place – increasing reliability for Riverside customers by providing a geographically diverse second point of interconnection that does not depend solely on one set of SCE infrastructure operating perfectly.

I also have other concerns relating to reliability considerations during the actual reactor installation activities if SCE were to implement this suggestion. Most likely, SCE would have to install two reactors, one between West bus sections of the A and C sections and one between the East bus sections of the A and C sections at Vista Substation and they would be installed sequentially. While one installation is being performed, that bus section would have to be taken out of service to allow workers to safely install the reactor, and then vice versa. During the outage time for the portions of the bus being addressed, the remaining operating bus sections would be the *only* source of power for all of Vista Substation's customers (SCE, Colton, and Riverside), leaving them without a backup redundant source in the event a contingency situation were to arise.

E. The Suggestion That Simple Switching Procedures Could Accommodate Adequate Load Transfers Is Based On Outdated Demand Information And Would Still Result In Unacceptable Load Shedding.

In a similar argument, the *Lewis Testimony* also suggests that by implementing a "switching" procedure, SCE could transfer load among various existing components such that as little as 10 MVA of load would remain at risk. This is also a flawed assumption for several reasons. For one, it assumes that all RPU generation would be available and operational to support Riverside's needs at any given time. As mentioned above, SCE does not consider such generation to be dependable for planning purposes, particularly over the long term.[40] Second, the 10 MVA amount identified in the *Lewis Testimony* was provided in a data request response referencing historical 2018 recorded load data, not future projected load as would be appropriate for forecasting purposes. Neither Riverside nor SCE projects load values over the next 10 years that would be as low as 2018 recorded data. Therefore, a significantly higher amount of load would be at risk even if, in a "perfect world," all of RPU's generation resources were able to be dispatched.

Regardless, the *Lewis Testimony's* argument still concedes that some level of load would be at risk even with this option. In my experience, it is SCE's practice to strive to achieve solutions to feasibly ensure reliable service to load during *all* base case and likely contingency events until additional infrastructure is built, rather than being content to allow some customers to be left in the dark. That is especially true in areas characterized as dense urban loads, like Riverside.

In conclusion, the alternative procedures suggested in the *Lewis Testimony* would not be workable and in fact could lead to negative impacts that would not be present if the proposed RTRP is built. Under the proposed RTRP:

- No load would be at risk of loss of service during normal base case conditions.
- No load would be at risk under reasonable and likely N-1 contingency events, even with a transformer outage at Vista Substation and a simultaneous RPU generating unit outage.
- Reliability to Riverside's customers would be improved through providing a diversified second source of power.
- SCE would avoid intentionally reducing reliability to both its customers and Riverside's customers to address likely N-1 contingency events.

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[40] As defined in the *SCE Criteria*, local dispatchable generation is considered "dependable" when the reasonably expected output amount of a generation source is on-line at least 90% of the peak demand hours during the months of July, August, and September for the previous year. Any generation that does not meet this criterion is considered not to be dependable and is not considered by SCE for use in planning. (*See* Attachment II-6, Appendix A.) Based on SCE's data, RPU's generation resources have not met this dependability criteria for at least the past five years.

- SCE would not have to operate and facilities (e.g., transformers, conductors, circuit breakers, etc.) above normal or at emergency ratings to accommodate both base case normal conditions and emergency conditions.
- Based on the alternatives discussed in this testimony, neither SCE or Riverside would have to consider the potential of involuntary load shedding as a means to ensure loading limits were maintained under normal or emergency conditions.
- Operational flexibility would be significantly improved for Riverside's electrical system.
- Continued reliance on Riverside's generation would not be required to meet load requirements under normal or emergency conditions and would be consistent with state policy and other initiatives to reduce GHG emissions and support renewable energy goals.
- In the event of a Vista transformer failure, all line position circuit breakers would still be operating within their rated limits and in normal configurations, ready to operate and isolate faulted elements should the next contingency occur.
- Any outage durations within Riverside's service territory would likely be only momentary, whereas much longer durations as have been experienced in the past.

Q: ***Would you please respond to the statement in the Lewis Testimony recommending that the CPUC require SCE and RPU to study additional low voltage alternatives that might incrementally address Riverside's needs, based on CEC peak load forecast data?***

A: Aside from the fact that the *Lewis Testimony*'s suggestion that yet another alternative analysis be undertaken disregards the CPUC's CEQA process, I do not believe that any analysis of incremental lower voltage options would provide any reasonable alternative to those already considered by SCE, RPU, CAISO and the CPUC. The *Lower Voltage and Other Design Alternatives Report* ("*LVODAR*") prepared by SCE and RPU, with assistance from CAISO, thoroughly discusses the potential environmental impacts associated with building new subtransmission lines to serve Riverside. As explained in the *LVODAR*, the subtransmission lines needed to provide enough power to Riverside would cause environmental impacts comparable to or worse than RTRP, given the habitat, residential neighborhoods and other features through which those routes would have to be developed.

In addition, as explained in the *LVODAR*, in order to avoid paralleling components that could risk spreading faults across both RPU and SCE systems, any additional subtransmission connection alternative would require RPU to split its system into discrete load pockets that are electrically isolated from one another. Much like the suggested transfer of some load to the San Bernardino lines, such separation of load would result in only a portion of RPU's system being served with redundant power, while the remainder of RPU's customers would still be left without any secondary source.[41]

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.

[41] In addition, to the extent that the *Lewis Testimony* suggests that a supplemental alternatives analysis be prepared to consider projects sized to meet demand forecasted by the CEC as opposed to RPU, I disagree with that suggestion as well. As mentioned above, I am informed and believe that RPU has prepared rebuttal testimony with evidence as to why the CEC's forecast is inaccurate and should not be relied upon for purposes of assessing RPU's future demand. That same rationale also would apply to any analysis of approaches to accommodate that demand.

III.

SCE's Rebuttal Testimony Regarding SCE's Satisfaction Of Various Regulatory Requirements Relevant To Wildfire And The Qualifications Of Mustafa Ali [42]

Q: ***Please state your name and business address for the record.***

A: My name is Mustafa Ali, and my business address is 1 Innovation Way, Pomona, CA 91768.

Q: ***Briefly describe your education, work history and present responsibilities at SCE.***

A: I graduated with a Bachelor of Science degree in Electrical Engineering in 1999 and a Master's in electrical engineering from California State University, Long Beach in 2008. In 2008, I became a Registered Professional Electrical Engineer with the State of California. I have worked for Southern California Edison Company (SCE) for16 years in the area of transmission engineering. Presently, I am the Senior Manager of the Transmission, Civil & Geo-Tech Engineering Group for SCE. In this position, I'm responsible for managing Transmission Power Lines System projects/scopes from design, review, licensing to execution. In addition, I am responsible for managing the engineering teams that respond to transmission power system emergencies including those related to wildfire.

Q: ***Please describe your role with respect to the Riverside Transmission Reliability Project (RTRP).***

A: I have no official role with respect to RTRP. However, as the Senior Manager of the Transmission, Civil & Geo-Tech Engineering Group, I lead a team that supports SCE's efforts to comply with various legislative and regulatory requirements with respect to the mitigation of wildfire risk. Specifically, I help SCE to design and support the implementation of improvements to SCE's subtransmission and transmission facilities in support of its Wildfire Mitigation Plans pursuant to

[42] This Section responds to Intervenor Direct Testimony and addresses Scoping Memo Issues ## 5 ("*Are the mitigation measures or project alternatives infeasible? This issue encompasses consideration of community values pursuant to Pub. Util. Code § 1002(a)(1)*") and 6 (whether the Project merits Commission approval notwithstanding the Project's significant and unavoidable impacts).

California Senate Bill ("SB") 901, Dodd. Wildfires (2018) ("SB 901") and California Public Utilities Code Section 8386,[43] among others.

Q: ***What is the purpose of your testimony in this proceeding?***

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Rebuttal Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to: (a) SCE strategies, programs and activities that are in place to proactively address and mitigate the threat of electrical infrastructure-associated ignitions that could lead to wildfires; (b) how SCE's risk-informed efforts to comply with existing wildfire laws and regulations will further mitigate wildfire ignitions from SCE's electric facilities associated with transmission voltages (above 50 kV); and (c) whether SCE proposes additional undergrounding to further mitigate the risk of wildfire ignition from RTRP's proposed facilities. In support of this testimony, I reviewed intervenor testimony relevant to the risk of

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[43] SB 901 is available here: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB901 (last checked August 15, 2019), and is incorporated herein by reference. *See also* the CPUC's Utility Wildfire Mitigation Plans (SB 901) website is available here: https://www.cpuc.ca.gov/SB901/ (last checked August 15, 2019), is incorporated herein by reference. *Southern California Edison Company's (U 338-E) 2019 Wildfire Mitigation Plan* dated February 6, 2019 ("SCE 2019 WMP") available here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M263/K645/263645320.PDF (last checked August 15, 2019), is incorporated herein by reference and is included as Attachment III-1 for convenience; the California Public Utilities Commission's June 3, 2019 *Guidance Decision On 2019 Wildfire Mitigation Plans Submitted Pursuant To Senate Bill 901* ("CPUC WMP Guidance Decision") available here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M296/K577/296577466.PDF (last checked August 15, 2019), is incorporated herein by reference and is included as Attachment III-2 for convenience; the California Public Utilities Commission's June 4, 2019 *Decision on Southern California Edison Company's 2019 Wildfire Mitigation Plan Pursuant To Senate Bill 901* ("CPUC SCE 2019 WMP Decision") available here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M298/K487/298487636.PDF (last checked August 15, 2019), is incorporated herein by reference and is included as Attachment III-3 for convenience; SCE's 2019 Wildfire Mitigation Plan Presentation (Feb. 13, 2019) available here: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SCE__WMP%20Presentation_20190213.pdf (last checked August 15, 2019), is incorporated by reference and is included as Attachment III-4 for convenience; CPUC Website, *Utility Wildfire Mitigation Plans (SB 901)* available here: https://www.cpuc.ca.gov/SB901/ (last checked August 15, 2019); SCE's Website, Our Wildfire Safety Measures available here: https://www.sce.com/safety/wildfire (last checked August 15, 2019).

wildfire including the *Direct Testimony of Penny Newman On Behalf Of The City Of Jurupa Valley* ("Newman Testimony").

Q: *Please explain your understanding of the Riverside Transmission Reliability Project*.

A: In or around 2008, I worked as an engineer supporting the siting and transmission design of RTRP. More recently, I became familiar with RTRP's current status and design through conversations with colleagues, as well as my review of the Final Environmental Impact Report for the Riverside Transmission Reliability Project adopted by the City of Riverside on or about February 6, 2013 (the "2013 FEIR") and the California Public Utilities Commission Riverside Transmission Reliability Project Final Subsequent Environmental Impact Report ("2018 SEIR") supporting SCE's CPCN Application in this proceeding. Specifically, I reviewed the sections of the 2013 FEIR and 2018 SEIR relevant to the Project description, as well as wildfire and hazards. My understanding is that the 2013 FEIR and 2018 SEIR are both already part of the administrative record in this proceeding.

Relevant to my testimony here, I understand that SCE's proposed Hybrid Alternative for RTRP envisions the construction of approximately 10 miles of double-circuit 220 kV transmission line, passing through portions of the City of Jurupa Valley ("Jurupa Valley") connecting proposed substation facilities to a tie in point on the Mira Loma-Vista #1 230-kV Transmission Line. Approximately 2-miles of RTRP is proposed by SCE to be located underground in the streets of Jurupa Valley, while SCE proposes overhead construction for the remaining portions of the proposed transmission line. SCE proposes to locate approximately 3-miles of overhead transmission line within designated Tier 2 High Fire Threat District ("HFTD") which runs adjacent to and parallels the Santa Ana River.[44]

A. <u>Compliance With Existing Regulations Applicable Across SCE's Service Territory Reduces The Risk Of Wildfire</u>

Q: *What existing utility regulations help to mitigate the risk of wildfires?*

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[44] *See SCE Proposed Hybrid overlaid with CPUC High Fire Threat Map*, included as <u>Attachment III-5</u>; *see also* CPUC Website, *Fire-Threat Maps & the High Fire-Threat District (HFTD), HFTD Map - GIS web viewer applet*, available here: https://ia.cpuc.ca.gov/firemap/ (last checked August 15, 2019), a relevant screenshot of which is included herein as <u>Attachment III-6</u>.

A: There are numerous existing regulations and standards which regulate utility activities which have the effect of mitigating the risk and impacts of wildfire, including Commission General Orders 95 (*Rules for Overhead Electric Line Construction*),[45] 165 (*Inspection Requirements for Electric Distribution and Transmission Facilities*),[46] and 166 (*Standards for Operation, Reliability, and Safety During Emergencies and Disasters*). Further, as part of other ongoing efforts to protect customers and communities from the risk of wildfires, SCE proposed wildfire safety measures as part of its $582 million Grid Safety and Resiliency Program (GS&RP), which aligns with SCE's Wildfire Mitigation Plans ("WMP") required under Senate Bill ("SB") 901, discussed below.[47]

B. <u>Compliance With The Recently Revised Public Utilities Code Section 8386 Is Specifically Intended To Reduce The Risk Of Wildfire</u>

Q: ***What does SB 901 require of SCE?***

A: SB 901 enacted changes to California Public Utilities Code Section 8386, building on existing Commission-regulated wildfire mitigation and vegetation management plans. SB 901 provides for a comprehensive plan of action for forest management and wildfire mitigation and suppression across the State in multiple sectors. With respect to utility infrastructure-related wildfire risks, SB 901 requires electrical corporations such as SCE to submit WMPs each year.[48] Each WMP must address 19 independent elements,[49] including:

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[45] Commission General Order 95, available here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M217/K418/217418779.pdf (last checked August 15, 2019), is incorporated herein by reference herein.

[46] Commission General Order 165, available here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K552/209552704.pdf (last checked August 15, 2019), is incorporated herein by reference herein.

[47] *See* SCE's *Prepared Testimony in Support of Southern California Edison Company's Application for Approval of Its Grid Safety and Resiliency Program* (September 10, 2018), available here: https://www.edison.com/content/dam/eix/documents/investors/wildfires-document-library/201809-gsrp-filing.pdf (last checked August 15, 2019).

[48] *See* Pub. Util. Code Section 8386(b) ("Each electrical corporation shall annually prepare and submit a wildfire mitigation plan to the division for review and approval. In calendar year 2020, and thereafter, the plan shall cover at least a three-year period. The division shall establish a schedule for the submission of subsequent comprehensive wildfire mitigation plans, which may allow for the staggering of compliance periods for each

(*Continued*)

- "Protocols for … deenergizing portions of the electrical distribution system that consider the associated impacts on public safety, as well as protocols related to mitigating the public safety impacts of those protocols, including impacts on critical first responders and on health and communication infrastructure";[50]
- Actions the utility will pursue "to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement";[51]
- The utility's "preventative strategies and programs … to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks";[52]
- Metrics to evaluate the WMP's performance;[53]
- A ranking of "all wildfire risks, and drivers for those risks," throughout the utility's service territory, which shall include wildfire risk and risk mitigation information contained in the utility's Safety Model Assessment Proceeding (S-MAP) and Risk Assessment Mitigation Phase (RAMP) filings, (Commission-mandated programs to compel risk-based utility management and spending);[54]

Continued from the previous page
electrical corporation. In its discretion, the division may allow the annual submissions to be updates to the last approved comprehensive wildfire mitigation plan; provided, that each electrical corporation shall submit a comprehensive wildfire mitigation plan at least once every three years.").

49 *See* CPUC WMP Guidance Decision at 9 ("Public Utilities Code Section 8386(c) contains a list of 19 elements each electrical corporation must include in its WMP").

50 *See* Pub. Util. Code § 8386(c)(6).

51 *See* Pub. Util. Code § 8386(c)(12).

52 *See* Pub. Util. Code § 8386(c)(3).

53 *See* Pub. Util. Code § 8386(c)(4).

54 *See* Pub. Util. Code § 8386(c)(10).

- Vegetation Management Plans;[55]
- Inspection plans for the utility's electric infrastructure;[56] and
- Improvements to the Commission's fire mapping.[57]

Q: ***What is your understanding of the Commission's role with respect to SCE's WMPs?***

A: I understand the Commission's task pursuant to SB 901 is to approve, subject to modification, each of SCE's WMPs after verifying compliance with "all applicable rules, regulations, and standards, as appropriate."[58]

Q: ***Is SCE required to file a WMP every year?***

A: Currently, yes.[59] California Public Utilities Code Section 8386(b) requires that

> [e]ach electrical corporation shall annually prepare and submit a wildfire mitigation plan to the division for review and approval. In calendar year 2020, and thereafter, the plan shall cover at least a three-year period. The division shall establish a schedule for the submission of subsequent comprehensive wildfire mitigation plans, which may allow for the staggering of compliance periods for each electrical corporation. In its discretion, the division may allow the annual submissions to be updates to the last approved comprehensive wildfire mitigation plan; provided, that each electrical corporation shall submit a comprehensive wildfire mitigation plan at least once every three years.

It is SCE's, and my understanding, that the Commission expects that subsequent WMPs will build upon the prior MP and improve with each iteration. To this end, the Commission requires SCE to

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[55] *See* Pub. Util. Code § 8386(c)(8).

[56] *See* Pub. Util. Code § 8386(9).

[57] *See* Pub. Util. Code § 8386(c)(14).

[58] *See* Pub. Util. Code § 8386(d); CPUC Guidance Decision at 11-13.

[59] *See* California Public Utilities Code § 8386(b) (annual WMP until 2020 and thereafter, each WMP covers at least 3 years).

report, monitor, evaluate and update its practices to ensure SCE is targeting the greatest wildfire risks with effective programs.[60] SCE is required to continue to comply with existing laws, regulations and Commission General Orders as they are updated and improved.[61]

Q: ***Has the Commission approved SCE's most recent 2019 WMP?***

A: Yes, subject to certain requirements that have since been completed, the Commission approved SCE's 2019 WMP on June 4, 2019.[62]

C. Coordination Between The Commission And CAL FIRE Promotes Continuous Improvement In SCE's Efforts To Mitigate Wildfire Risk

Q: ***Has the Commission consulted with the California Department of Forestry and Fire Protection ("CAL FIRE") regarding the review of SCE's WMP?***

A: Yes, according to the June 3, 2019 CPUC WMP Guidance Decision, "SB 901 requires that the Commission and CAL FIRE consult on the review of each wildfire mitigation plan … and that the two agencies have a memorandum of understanding in place to facilitate this consultation …. The Commission has met these requirements …"[63]

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[60] *See* CPUC WMP Guidance Decision at 5 ("We hope and expect improvement in the Wildfire Mitigation Plans each year through engineering and technological advances, but we will not solve the problem of catastrophic wildfires in one year. We and the electrical corporations we oversee are but a piece of the solution to mitigating catastrophic wildfires."), 38 ("The WMP decisions the Commission issues in this proceeding are but one action the state and its regulated electrical corporations will take to mitigate the risk of catastrophic wildfire. This will be an annual process, and we expect continuous improvement as our actions here are an important element of the collective state efforts to mitigate risks of catastrophic wildfires. As such, the annual WMP process will be iterative, and will require reporting, monitoring, evaluation and updating to ensure the electrical corporations are targeting the greatest risk with effective programs.").

[61] *See* CPUC Decision re SCE 2019 WMP at 12 ("Nothing in this decision relieves SCE of the requirement to conform its WMP activities to existing law, regulation and General Orders").

[62] *See* CPUC SCE 2019 WMP Decision at 51 – 52 ("Southern California Edison's (SCE's) Wildfire Mitigation Plan (WMP) contains the elements required by Public Utilities Code Section 8386(c). Subject to the reporting, metrics, data and advice letter requirements set forth below, SCE's WMP is approved…")

[63] *See* CPUC WMP Guidance Decision at 37-38, *citing* California Public Utilities Code §§ 8386(b) (annual WMP until 2020 and thereafter, each WMP covers at least 3 years), 8386.5 ("The commission and the Department of Forestry and Fire Protection shall enter into a memorandum of understanding to cooperatively develop consistent approaches and share data related to fire prevention, safety, vegetation management, and energy distribution systems. The commission and the department shall share results from various fire prevention activities, including relevant inspections and fire ignition data"). The *Memorandum of Understanding Between*

(*Continued*)

D. SCE Tailors Its Actions To Mitigate Wildfire Risk Pursuant To An Analysis Of Risks Posed And Transmission Facilities Are Involved In A Relatively Small Percentage Of Ignition Events In SCE's Service Territory

Q: ***Does SCE distinguish between distribution and transmission efforts in its WMPs, and if so, why?***

A: Yes, SCE does distinguish between efforts aimed at limiting wildfire risk to distribution-level facilities, designated in the WMP to be facilities operating at voltages of 33 kV and below, and subtransmission and transmission-level facilities designated in the WMP to be facilities operating at voltages in excess of 55 kV.[64]

As part of SCE's development of its WMP, SCE set about identifying, describing and prioritizing wildfire risks and risk drivers within its service territory by analyzing recent data between 2015 and 2017. SCE first determined the parts of its system that are at the highest risk of ignition, followed by an analysis of drivers and outcomes for wildfire ignitions in those areas. SCE analyzed the frequency and consequence of ignitions by categorizing its system based on two factors: (1) system voltage level (*e.g.*, distribution voltage or transmission voltage); and (2) whether the ignition occurred within an SCE-defined HFRA. HFRA are areas in SCE's service territory where there is an elevated hazard for the ignition and rapid spread of fires associated with electrical equipment due to

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the California Public Utilities Commission and the California Department of Forestry and Fire Protection ("CAL FIRE CPUC MOU") is available here: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/170907%20CPUC-CAL%20FIRE%20MOU%20FINAL%20SIGNED.pdf (last checked August 15, 2019), is incorporated herein by reference and is included as Attachment III-7 for convenience.

[64] *See* SCE 2019 WMP at 19-20 ("Over the 2015-2017 time period, SCE experienced 302 reportable ignition events associated with electrical infrastructure within its service territory. 92 percent of these ignitions occurred at distribution level voltages (33 kilovolt (kV) and below), while eight percent occurred at subtransmission and transmission level voltages (55 kV and above). When analyzed based on presence in HFRA, 50 percent of these ignitions occurred in HFRA, and 50 percent occurred outside of HFRA").

topographical and climatological risk factors such as strong winds, abundant dry vegetation, and other environmental conditions.[65]

As described in Figure 3-1 of SCE's 2019 WMP (*Four Tranches of SCE Risk Analysis Based on Frequency and Consequence Considerations*, included below for convenience), during the analyzed period the vast majority of electrical infrastructure-related ignitions associated with SCE's system have been located on the distribution voltage-level system. Over the 2015-2017 time period, 50 percent of these ignitions occurred in HFRA, and 50 percent occurred outside of HFRA. In total, SCE experienced 302 CPUC-reportable ignition events associated with electrical infrastructure within its service territory from 2015 to 2017. 92 percent (281 events) of the 302 reportable ignitions occurred at distribution level voltages (33 kV and below), while 8 percent (19 events) occurred at subtransmission and transmission level voltages (55 kV and above).[66] Only 2 of these 19 events (*i.e.*, less than 0.7 percent of the ignitions in 2015 – 2017) were associated with transmission facilities in excess of 200 kV, such as those proposed for RTRP.

Based on both frequency and consequence considerations, SCE identified distribution equipment within SCE's HFRA as the specific tranche of assets that poses the most significant wildfire risk. SCE considers the tranche of HFRA distribution assets, representing approximately 44 percent of all ignition events associated with SCE facilities during the studied period, to have the highest frequency and the highest potential consequence of ignitions of the four tranches.[67]

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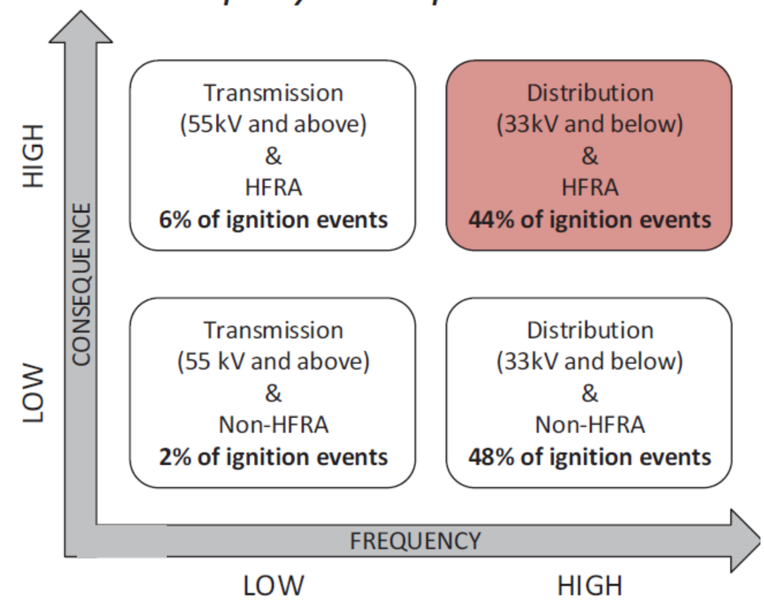
[65] *See* SCE 2019 WMP at 19.

[66] *See* SCE 2019 WMP at 19-20, Tbl. 3-3.

[67] *See* SCE 2019 WMP at 20.

Figure 3-1
Four Tranches of SCE Assets for Risk Analysis
Based on Frequency & Consequence Considerations



Therefore, SCE's risk analyses performed to date have prioritized evaluation and mitigation of wildfire risk within this tranche: distribution equipment within SCE's HFRA.[68] California Public Utilities Code Section 8386 specifically mandates that SCE undertake a risk-based approach to minimize the risk of catastrophic wildfire posed by the electrical lines and equipment SCE constructs, maintains, and operates.[69]

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[68] *See* SCE 2019 WMP at 20.

[69] *See* PUC § 8386(a) ("Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment"); *see also* PUC §§ 8386 (c)(10), (11), & (15) ("The wildfire mitigation plan shall include all of the following:…(10) A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of Safety Model Assessment Proceeding and Risk Assessment Mitigation Phase filings. The list shall include, but not be limited to, both of the following: (A) Risks and risk drivers associated with design, construction, operations, and maintenance of the electrical corporation's equipment and facilities.
(B) Particular risks and risk drivers associated with topographic and climatological risk factors throughout the different parts of the electrical corporation's service territory. (11) A description of how the plan accounts for the wildfire risk identified in the electrical corporation's Risk Assessment Mitigation Phase filing. … (15) A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with the methodology used by other electrical corporations unless the commission determines otherwise.")

Q: ***Despite SCE's primary focus on distribution-level infrastructure for fire risk mitigation programs, is SCE also pursuing programs and practices through its WMP that are relevant to SCE's transmission facilities like RTRP, i.e., transmission-level voltages partially located in HFRA?***

A: Yes. As described in SCE's 2019 WMP and the CPUC's Decision approving same, SCE is implementing various programs and practices to mitigate the risk of wildfire associated with transmission-level (in excess of 50 kV) facilities, including:

- <u>*Inspection and Maintenance*</u> [70]
  - *Enhanced Overhead Inspections and Remediation*, which conducts inspections of all overhead transmission and distribution structures and equipment in HFRA for potential ignition risks;
  - *Annual Grid Patrol*, which visually inspects SCE's overhead and above-ground equipment associated with otherwise undergrounded electrical distribution facilities every year to identify and document obvious safety and reliability conditions that require corrective action;
  - *Transmission Inspection and Maintenance Program*, which performs scheduled inspections of sub-transmission and transmission assets in compliance with GO 165, and performs transmission maintenance in accordance with GO 95, 128 and SCE's standards;
  - *Substation Inspection and Maintenance*, which performs scheduled inspections in conformance with GO 167, and performs maintenance and testing of equipment;
  - *Quality Oversight/Quality Control Group*, which performs independent evaluation of SCE's inspection and maintenance activities to ensure compliance with GO 95, 128, 164, 174 and SCE's standards; and
  - *Transmission Infrared and Corona Inspection Initiative*, which inspects all overhead transmission facilities and equipment located in HFRA using specialized infrared and ultraviolet (Corona) light cameras mounted to helicopters.
- <u>*Vegetation Management*</u> [71]

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[70] *See* CPUC Decision re SCE's 2019 WMP at 8-9.

➢ *Hazard Tree Removals*. Enhancing assessment of the structural condition of trees in HFRA that could fall into or otherwise impact electrical facilities and potentially lead to ignitions and outages;

➢ *Drought Relief Initiative Quarterly Inspections and Tree Removals* conducts quarterly inspections in Tier 2 and Tier 3 areas within SCE's HFRA for tree mortality to identify and remove dead, dying or diseased trees that were affected by the drought and bark beetle infestation; and

➢ *Light Detection and Ranging Technology (LiDAR) Inspection Program* to assess vegetation clearances of transmission lines in rugged and hard-to-access areas.

▪ De-Energization [72]

➢ *SCE's protocol for De-energization* or PSPS consists of a set of de-energization criteria and guidelines that SCE can use under a variety of weather and physical circumstances and electrical system operating conditions.

▪ Situational Awareness and Alternative Technologies [73]

➢ *Installing weather stations*. SCE requires precise weather data to manage risks in its system, given the size of SCE's service territory and its diverse topography. To obtain such granular weather data, SCE needs a dense network of weather stations to monitor location-specific, real-time

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[71] *See* CPUC Decision re SCE's 2019 WMP at 18-19. SCE's existing vegetation management program involves tree inspection, pruning and removal, and weed abatement for vegetation in close proximity to SCE's distribution and transmission lines in compliance with Commission vegetation-related regulations, including but not limited to General Order 95, California Public Resources Code Sections 4291-93, and North American Electric Reliability Corporation ("NERC") Reliability Standard FAC-003. SCE's vegetation management program is currently undergoing a comprehensive redesign and restructuring. Those efforts are described in SCE's 2019 WMP and elements relevant to transmission facilities are listed here.

[72] *See* CPUC Decision re SCE's 2019 WMP at 24-26. The Commission is examining de-energization (also known as Public Safety Power Shut-Off or PSPS) in depth in R.18-12-005. To the extent the Commission authorizes new requirements in R.18-12-005, those requirements will automatically apply once adopted. Thus, de-energization is on the list of items that WMPs must cover but is subject to the ongoing considerations being made in R.18-12-005.

[73] *See* CPUC Decision re SCE's 2019 WMP at 29-31.

conditions in HFRA. These weather stations will monitor wind and relative humidity data on a circuit-by-circuit basis.

➢ *Using the Fire Potential Index (FPI) and Santa Ana Wildfire Threat Index (SAWTI) to monitor fire risks*. The Fire Potential Index (FPI) is an internal tool SCE uses to estimate wildfire potential based on actual weather and fuel conditions. In addition to the FPI, SCE also monitors the SAWTI, issued by the United States Forest Service (USFS), which measures the severity of Santa Ana winds with respect to the potential for large fires to occur.

➢ *Increasing Meteorological Resources*. Using forecasting tools and weather stations, SCE's in-house team of meteorologists will develop comprehensive weather forecasts 4-7 days in advance of any predicted severe weather event.

➢ *Deploying and Installing Situational Awareness Cameras*. SCE will install pan-tilt-zoom (PTZ) High Definition (HD) cameras throughout its HFRA to enable fire agencies and SCE fire management personnel to address emerging wildfire more quickly. The cameras can help in spotting smoke and assessing conditions in real-time.

➢ *Installing a High-Performance Computer Cluster (HPCC).* SCE will install a HPCC that will generate forecasts of weather and fuel conditions at high resolution. The HPCC will comprehensively assess wildfire risk across the area.

➢ *Developing Asset Reliability and Risk Analytics Capability*. Under this program, SCE seeks to: (1) develop capabilities in predicting an asset's overall wildfire-related risk; and (2) given an asset's risk, prioritize mitigation efforts. SCE will use analytics and composite risk models to guide the prioritization of mitigation efforts. SCE also seeks to use advanced analytic capabilities, artificial intelligence, machine learning, and predictive modeling with real-time data to improve advanced fault detection identification.

- *Emergency Preparedness, Outreach and Response Planning* [74]
  - *SCE's has developed emergency preparedness and response plans* which follow National Incident Management System (NIMS) and Incident Command System (ICS) principles and protocols (developed by the Federal Emergency Management Agency (FEMA)) in order to minimize the impacts of emergencies on customers and communities, including a plan for communicating with its customers during emergencies such as outages and maintaining an adequate and trained workforce ready to provide assistance during emergencies;
  - *SCE's Storm Plan* follows the recovery, restoration, and remediation guidelines established by Commission pursuant Public Utilities Code Section 768.6, describing the operations and policies for responding to emergency electrical disruptions caused by exogenous natural forces and for facilitating safe and efficient restorations.
- *Support to Utility Customers During and After a Wildfire* [75]
  - The Commission has adopted certain customer protections available in the event the Governor of California declares a state of emergency because a disaster has either resulted in the loss or disruption of the delivery or receipt of utility service and/or resulted in the degradation of the quality of utility service. In such circumstances, SCE will implement various customer protections, including: (a) support for low-income customers; (b) billing adjustments; (c) deposit waivers; (d); extended payment plans; (e) suspension of disconnection and nonpayment fees; (f) repair processing and timing; (g) access to utility representatives; (h) outage reporting; and (g) emergency communications.

E. SCE Does Not Propose Additional Undergrounding In The Case Of RTRP To Further Mitigate Wildfire Risk

Q: Does SCE propose undergrounding any of its facilities as part of its 2019 WMP, and if so, under what conditions?

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[74] *See* CPUC Decision re SCE's 2019 WMP at 34-35.

[75] *See* CPUC Decision re SCE's 2019 WMP at 39.

A: I understand SCE is currently conducting an evaluation to identify portions of its HFRA where targeted undergrounding may be necessary because the risk of ignitions from overhead facilities cannot be sufficiently mitigated. Generally, SCE is evaluating the targeted undergrounding of certain distribution-level facilities as part of SCE's system hardening efforts. For example, SCE's *Undergrounding Overhead Conductor Program* (sometimes referred to as SCE's *Targeted Undergrounding Program*) will aim to identify locations where placing overhead distribution lines underground will reduce the risk of wildfires and increase reliability during high winds and storms.[76]

Q: ***Does SCE recommend undergrounding sections of the Hybrid Alternative to further mitigate wildfire risk associated with RTRP's proposed transmission lines?***

A: The determination of whether any specific SCE facilities should be undergrounded is fact-specific and depends on the evaluation of numerous factors. First, I understand that with the imposition of mitigation measures and applicant proposed measures described in the 2018 SEIR, as well as taking into account existing Commission regulations, RTRP is not expected to result in significant, unavoidable impacts to fire safety.[77] Further, based on the limited risks entailed by transmission facilities above 200 kV and consistent with the efforts described in SCE's WMP and herein, SCE does not recommend undergrounding the approximately 3 miles of RTRP's proposed 220 kV transmission-level facilities within the Tier 2 HFRA to further mitigate the risk of wildfire ignition from these facilities.

As described above, California Public Utilities Code Section 8386 requires that SCE employ risk-based assessments. As suggested by Figure 3-1 and SCE's evaluations to date, only 6 percent of

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[76] *See* CPUC Decision re SCE's 2019 WMP at 14.

[77] *See* 2018 SEIR at M-3.1-13 ("…The 230-kV transmission line traverses the boundary of a Tier 2 HFTD south of the Hidden Valley Wildlife Preserve. Within Tier 2 areas, GO 95 now requires stricter fire-safety measures related to corrections of safety hazards, vegetation clearance requirements, facility inspections, and the annual preparation of a fire prevention plan. SCE is required by law to adhere to GO 95. Additionally, MM HAZ-03 from the certified 2013 RTRP EIR requires the preparation of a Fire Prevention and Management Plan and would ensure that project construction complies with the applicable fire regulations, including GO 95. *The CPUC's new fire regulations would further increase fire-safety in the project area and the impact would remain less than significant.* Additional analysis of fire hazards related to the 230-kV transmission line and Revised Project is not required" (emphasis added)).

ignition events are caused by electrical facilities that are both in excess of 55 kV and in HFRA. That percentage decreases to less than 0.7 percent for facilities in excess of 200 kV, such as the facilities proposed for RTRP. Under these circumstances and based on my understanding of the wildfire risks from SCE's facilities, SCE does not propose additional undergrounding in the case of RTRP to further mitigate wildfire risk.

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.

IV.

SCE's Rebuttal Testimony Regarding The Anticipated Cost Of The Acquisition Of Real Property Rights In Support Of The Construction Of Project Alternatives, The Impacts Of Overhead Transmission Lines On Property Values, And The Qualifications Of Bradford Thompson [78]

Q: ***Please state your name and business address for the record.***

A: My name is Bradford Thompson, and my business address is Mason & Mason Real Estate Appraisers & Consultants, 2609 Honolulu Avenue, Suite 100, Montrose, California 91020.

Q: ***Briefly describe your relevant education, professional experience, and present responsibilities at Mason & Mason.***

A: I earned my Bachelor of Science Degree from the University of Southern California, Marshall School of Business, and a Master's Degree in Business Administration (MBA) from California Polytechnic University Pomona with an emphasis in urban and regional planning, real estate, and law. I completed by Master Thesis Project on the topic of Just Compensation – The Physical Partial Acquisition Through Eminent Domain.

I have worked in the appraisal field since 1989 and have been associated with Mason & Mason since 1991. I have performed a variety of appraisal functions including research and appraisal report preparation for varied property types, including industrial, commercial, retail, office, vacant acreage, and single and multi-family residential properties. I have prepared property valuations for eminent domain both total and partial takings, inverse condemnation, property tax appeals, bankruptcy, asset management, loan underwriting, and have provided litigation courtroom support and expert testimony for numerous trials. As a real estate and valuation consultant, I regularly review and analyze annexation documents, easement documents, lot line adjustments, parcel and tract maps, dedications, and right of way vacations.

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[78] This Section responds to Intervenor Direct Testimony and addresses Scoping Memo Issues ## 5 ("*Are the mitigation measures or project alternatives infeasible? This issue encompasses consideration of community values pursuant to Pub. Util. Code § 1002(a)(1)*") and 8 ("*What is the maximum prudent and reasonable cost of the project? (See Pub. Util. Code § 1005.5.)*").

I am a licensed California real estate broker and a Certified General Real Estate Appraiser in the states of California and Arizona. I have various designations from the Appraisal Institute, a professional association of real estate appraisers. Its mission is to advance professionalism and ethics, global standards, methodologies, and practices. Specifically, I am a Member of the Appraisal Institute (MAI), and have the designation of Appraisal Institute – General Review Specialist (AI-GRS), indicating my experience and knowledge to address issues unique to commercial real property reviews. I am also a designated Senior Right of Way Professional (SR/WA), a designation indicating that I have earned the most prestigious designation granted to those right of way professionals who have achieved professional status through experience, education and examination focused on the areas of right of way acquisition, valuation, engineering and real property law.

I have served as a Planning Commissioner for the City of Arcadia for the previous four years and sit as its Chair for 2018-2019. I am also qualified as an expert witness in real estate valuation in Los Angeles, Riverside and San Bernardino Superior Courts.

A complete statement of appraisal qualifications is attached hereto in Attachment IV-1.

Q: ***What is the purpose of your testimony in this proceeding?***

A: The purpose of my testimony in this proceeding is to sponsor this section of *Southern California Edison Company's (U 338-E) Rebuttal Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to my review of: (1) the Appraisal Report prepared by Jones, Roach & Caringella, Inc. regarding 102.43 acres of essentially vacant land ("APV Property); (2) the Appraisal Report prepared by Jones, Roach & Caringella, Inc. regarding 64.67 acres of essentially vacant land ("Sky Country Property); (3) the Appraisal Report prepared by Jones, Roach & Caringella, Inc. regarding 21.92 net acres of vacant land ("VTN Property"); and (4) the Appraisal Report prepared by Curtis-Rosenthal, Inc. regarding the Lesso-Thoroughbred Farms Property, 12071 Bellegrave Avenue, Jurupa Valley, CA. ("Lesso Mall Property"). My findings related to the Appraisal Reports for the APV, Sky Country, VTN, and Lesso Mall Properties are contained in the four Mason & Mason appraisal reviews included as Attachments IV-2 to IV-5 to SCE's Rebuttal Testimony.

I am also testifying regarding the impacts of overhead transmission lines on property values, a subject relevant to various intervenor testimonies, including that of Mssrs. Blaesi, Dukett, Newman, Platt, Roach, Rossman, and Thompson.

A. Anticipated Costs of the Acquisition of Real Property Rights in Support of the Project Alternatives Are Likely to be Significantly Less Than Intervenors Argue

Q: ***Please summarize your findings with respect to the Appraisal Report for the APV Property.***

A: We found the conclusions of the Appraisal Report for the APV Property prepared by Jones, Roach, and Caringella, Inc. ("Roach APV Appraisal Report") to not be reasonable in light of the data and analyses presented therein. As described in detail in the Mason & Mason *Appraisal Review of an Appraisal Report Prepared by Jones, Roach, and Caringella, Inc., 102.43 Acres Essentially Vacant Land, Anthony P. Vernola Trust Property, SEC of Bellegrave Avenue & I-15, Jurupa Valley, California* included as Attachment IV-2 here, the Roach APV Appraisal Report, among other things:

- contains significant material errors of fact or analysis that undermine its conclusions;
- employs analyses that are not appropriate and could be construed as misleading if not modified;
- lacks several extraordinary assumptions and/or hypothetical conditions per Uniform Standards of Professional Appraisal Practice (USPAP) Standard Rules[79] and relies on several third-party reports partially called out as extraordinary assumptions that, if erroneous, may have significantly affected the Roach APV Appraisal Report's conclusions;
- improperly relies on non-comparable sales data from properties which are distinct in character and/or entitlement status (*e.g.*, four of the most relevant comparable sales benefit from entitlements

[79] *See* USPAP Standard Rule 1-2 (f), (g) ("In developing a real property appraisal, an appraiser must: … (f) identify any extraordinary assumptions necessary in the assignment; (g) identify any hypothetical conditions necessary in the assignment…), 2-2(a)(xi) ("(a) The content of an Appraisal Report must be consistent with the intended use of the appraisal and, at a minimum: … (xi) clearly and conspicuously: [*] state all extraordinary assumptions and hypothetical conditions; and [*] state that their use might have affected the assignment results…"). USPAP Standard Rules are available here: https://appraiserelearning.com/wp-content/uploads/2018/09/2018-19-electronic-copy-of-USPAP.pdf (last checked August 15, 2019), and are incorporated herein by reference.

superior to the APV Property) calling into doubt the asserted value of the APV Property at $15.50/square foot;

- concludes that the subject remainder of the APV Property would be diminished by 10% but without support from relevant market data inconsistent with recognized appraisal practices; and
- applies an annual 9% rate of return to any temporary construction easements without support from relevant market data and despite the fact that current ground lease rates in the Inland Empire generally range from 4%-5%.

Based on our analysis, the conclusion of the Roach APV Appraisal Report are not reasonable, appropriate, or credible. Several modifications would be required to conform to the requirements of the USPAP Standard Rules and establish an analysis that is credible and appropriate to its stated purpose of "an appraisal of likely right-of-way acquisition costs for the RTRP Project, on those properties within the proposed RTRP Hybrid Alignment, located between Limonite and Bellegrave Avenues, and Pats Ranch Road and the I-15 Freeway, in the City of Jurupa Valley."[80] These and additional comments, observations, and potential deficiencies are discussed in greater detail in the Mason & Mason Appraisal Review included as Attachment IV-2 hereto.

Q: *Please summarize your findings with respect to the Appraisal Report for the Sky Country Property.*

A: We found the conclusions of the Appraisal Report for the Sky Country Property prepared by Jones, Roach, and Caringella, Inc. ("Roach Sky Country Appraisal Report") to not be reasonable in light of the data and analyses presented therein. As described in detail in the Mason & Mason *Appraisal Review of an Appraisal Report Prepared by Jones, Roach, and Caringella, Inc., 64.67 Acres Essentially Vacant Land, Sky Country Property, Limonite Avenue, Jurupa Valley, California* included as Attachment IV-3 here, the Roach Sky Country Appraisal Report, among other things:

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[80] *See* Roach Testimony at 2.

- lacks several extraordinary assumptions per USPAP Standard Rules;[81]
- improperly relies on non-comparable sales data from properties which are distinct in character and/or entitlement status as compared against the subject property (*e.g.*, only one comparable sale reflects the alleged highest and best use (mixed use, commercial and residential) land use type; other allegedly comparable sales benefit from superior entitlements; the majority of the sales data are from a more mature and otherwise unique location, *etc*.);
- omits relevant comparable sales data in close proximity to the subject property which average $15.28/square foot – considerably less than the $28/square foot asserted by the Roach Sky Country Appraisal Report;
- concludes that the subject remainder of the Sky Country Property would be diminished by 15% but without a valuation analysis and/or support from relevant market data, inconsistent with recognized appraisal practices (*e.g.*, opinions expressed by a small number of people (in this case two) do not adequately represent likely market participants or fair market value); and
- applies an annual 9% rate of return to any temporary construction easements without support from relevant market data and despite the fact that current ground lease rates in the Inland Empire generally range from 4%-5%.

Based on our analysis, the conclusions of the Roach Sky Country Appraisal Report are not reasonable, appropriate, or credible. Several modifications would be required to conform to the requirements of the USPAP Standard Rules and establish an analysis that is credible and appropriate to its stated purpose.[82] These and additional comments, observations, and potential deficiencies are

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[81] *See* USPAP Standard Rule 1-2 (f), (g) ("In developing a real property appraisal, an appraiser must: … (f) identify any extraordinary assumptions necessary in the assignment; (g) identify any hypothetical conditions necessary in the assignment…), 2-2(a)(xi) ("(a) The content of an Appraisal Report must be consistent with the intended use of the appraisal and, at a minimum: … (xi) clearly and conspicuously: [*] state all extraordinary assumptions and hypothetical conditions; and [*] state that their use might have affected the assignment results…").

[82] *See* Roach Testimony at 2 ("an appraisal of likely right-of-way acquisition costs for the RTRP Project, on those properties within the proposed RTRP Hybrid Alignment, located between Limonite and Bellegrave Avenues, and Pats Ranch Road and the I-15 Freeway, in the City of Jurupa Valley").

discussed in greater detail in the Mason & Mason Appraisal Review included as Attachment IV-3 hereto.

Q: ***Please summarize your findings with respect to the Appraisal Report for the VTN Property?***

A: We found the conclusions of the Appraisal Report for the Sky Country Property prepared by Jones, Roach, and Caringella, Inc. ("Roach VTN Appraisal Report") to not be reasonable in light of the data and analyses presented therein. As described in detail in the Mason & Mason *Appraisal Review of an Appraisal Report Prepared by Jones, Roach, and Caringella, Inc., 21.92 Net Acres Vacant Land, Vernola Trust North Property, Limonite Avenue, Jurupa Valley, California* included as Attachment IV-4 here, the Roach VTN Appraisal Report, among other things:

- contains significant material errors of fact or analysis that undermine its conclusions;
- employs analyses that are not appropriate and could be construed as misleading if not modified;
- lacks several extraordinary assumptions and/or hypothetical conditions per USPAP Standard Rules[83] and relies on several third-party reports partially called out as extraordinary assumptions that, if erroneous, may have significantly affected the Roach VTN Appraisal Report's conclusions. For example, the Roach VTN Appraisal Report assumes: that an acquisition is in fact, necessary; the scope and extent of that acquisition; the need and term of temporary construction easements; alleged impacts to a "construction agreement" and need for a zone change, *etc*.);
- omits relevant comparable sales data in close proximity to the subject property (including the 2016 sale of the adjacent Lesso Mall Property) which average $15.28/square foot – considerably less than the $30/square foot asserted by the Roach VTN Appraisal Report;
- concludes that the subject remainder of the VTN Property would be diminished by 5% absent a valuation analysis and/or support from relevant market data, inconsistent with recognized appraisal

[83] *See* USPAP Standard Rule 1-2 (f), (g) ("In developing a real property appraisal, an appraiser must: … (f) identify any extraordinary assumptions necessary in the assignment; (g) identify any hypothetical conditions necessary in the assignment…), 2-2(a)(xi) ("(a) The content of an Appraisal Report must be consistent with the intended use of the appraisal and, at a minimum: … (xi) clearly and conspicuously: [*] state all extraordinary assumptions and hypothetical conditions; and [*] state that their use might have affected the assignment results…").

practices (*e.g.*, opinions expressed by a small number of people (in this case two) do not adequately represent likely market participants or fair market value; inconsistencies between the percentage of the identified, subsurface acquisition area (1.8%) and corresponding alleged percentage diminution of the total property value (8.7%), *etc.*); and

- applies an annual 9% rate of return to any temporary construction easements without support from relevant market data and despite the fact that current ground lease rates in the Inland Empire generally range from 4%-5%.

Based on our analysis, the conclusions of the Roach VTN Appraisal Report are not reasonable, appropriate, or credible. Several modifications would be required to conform to the requirements of the USPAP Standard Rules and establish an analysis that is credible and appropriate to its stated purpose.[84] These and additional comments, observations, and potential deficiencies are discussed in greater detail in the Mason & Mason Appraisal Review included as Attachment IV-4 hereto.

Q: *Please summarize your findings with respect to the Appraisal Report for the Lesso Mall Property?*

A: We found the Appraisal Report for the Lesso Mall Property prepared by Curtis-Rosenthal, Inc. ("CR Lesso Mall Appraisal Report") to be unacceptable, not in conformity with the USPAP Standard Rules, and not in conformity with generally accepted appraisal practices and procedures. We would therefore recommend the rejection of the CR Lesso Mall Appraisal Report in light of the significant material errors of fact or analysis within that report.

As described in detail in the Mason & Mason *Appraisal Review of an Appraisal Report Prepared by Curtis-Rosenthal, Inc., Lesso-Thoroughbred Farms Property, 12071 Bellegrave Avenue, Jurupa Valley, California* included as Attachment IV-5 here, the CR Lesso Mall Appraisal Report, among other things:

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[84] *See* Roach Testimony at 2 ("an appraisal of likely right-of-way acquisition costs for the RTRP Project, on those properties within the proposed RTRP Hybrid Alignment, located between Limonite and Bellegrave Avenues, and Pats Ranch Road and the I-15 Freeway, in the City of Jurupa Valley").

- lacks several extraordinary assumptions and/or hypothetical conditions per USPAP Standard Rules;[85]
- omits relevant comparable sales data in close proximity to the subject property;
- does not consider the recent sale of the subject property on August 31, 2016 for $70,000,000 – which stands in sharp contrast to the currently alleged value of $143,277,540 – in violation of USPAP Standards;[86]
- misidentifies and/or erroneously analyzes comparable sales data;
- improperly relies on non-comparable sales data from properties which are distinct in character, entitlement status, and located a significant geographic distance away from the subject property;
- concludes that the subject remainder of the Lesso Mall Property would be diminished by 50% absent analysis or support from relevant market data;
- presents an estimate of severance damages which is unsupported and misleading, alleging damages result from effective extinguishment of the Specific Plan but if that were true, then the appraisal would have to assume that the market price or cost to process a single specific plan is $66,000,000 - this is simply not credible or believable; and
- alleges that a new Specific Plan would need to be prepared as a result of the project, which is a significant portion of the damage claim. As confirmed by the attorney representing the City of Jurupa Valley, the proposed project may warrant amendment of the Specific Plan, not a complete frustration of the existing partial entitlement.[87]

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[85] USPAP Standard Rule 1-2 (f), (g) ("In developing a real property appraisal, an appraiser must: … (f) identify any extraordinary assumptions necessary in the assignment; (g) identify any hypothetical conditions necessary in the assignment…), 2-2(a)(xi) ("(a) The content of an Appraisal Report must be consistent with the intended use of the appraisal and, at a minimum: … (xi) clearly and conspicuously: [*] state all extraordinary assumptions and hypothetical conditions; and [*] state that their use might have affected the assignment results…").

[86] USPAP Standard Rule 1-5 ("When the value opinion to be developed is market value, an appraiser must, if such information is available to the appraiser in the normal course of business: (a) analyze all agreements of sale, options, and listings of the subject property current as of the effective date of the appraisal; and (b) analyze all sales of the subject property that occurred within the three (3) years prior to the effective date of the appraisal.").

[87] *See* August 9, 2019 E-mail correspondence from B.Tilden Kim to Bradford Thompson, included as Attachment IV-6 ("Hypothetically, if an electrical utility acquired a 100+/- easement along the westerly and northerly edge of

(*Continued*)

These errors call into question the CR Lesso Mall Appraisal Report relevant to its asserted value of $30/square foot, alleged damages to the subject remainder of the Lesso Mall Property, and alleged severance damages of $66,000,000. These and additional comments, observations, and potential deficiencies are discussed in greater detail in the Mason & Mason Appraisal Review included as Attachment IV-5 hereto.

B. Intervenors' Projections of Impacts of Overhead Transmission Lines on Property Values and Potential Development Along the I-15 Corridor Are Speculative and Unsupported

Q: *Have you reviewed the testimony of Steven Dukett for the City of Jurupa Valley?*

A: Yes, I have.

Q: *What is your opinion regarding Mr. Dukett's testimony, and 2019-Fiscal and Economic Impact Analysis for the Riverside Transmission Reliability Project included as Exhibit A thereto?*

A: For a variety of reasons, I find Mr. Dukett's testimony and *2019-Fiscal and Economic Impact Analysis for the Riverside Transmission Reliability Project* (FEIA) flawed, speculative, and lacking foundational support and/or reference to relevant and available facts.[88] Mr. Dukett's conclusions regarding RTRP's impacts to population, employment, employee spending, and city fiscal impacts/tax revenues stem from the presumptions that: (1) that overhead transmission lines have a negative impact on property values;[89] and (2) development pursuant to the applicable specific plan will be forthcoming and developed by or before 2028.[90] Neither presumption is warranted here.[91]

Continued from the previous page
the Planning Area(s) would that prompt any amendment(s) to the existing SP and/or other entitlements? Yes. If yes, how so? It would require an amendment to the Specific Plan and Tentative Map.").

[88] Urban Futures, Inc. also developed a December 2, 2015 *Economic/Fiscal Impact Analysis* of RTRP for the City of Jurupa Valley. *See* Feb. 9, 2016 Correspondence from D.Cosgrove to J. Uchida, Exhibit K, included here as Attachment IV-11.

[89] *See* Dukett FEIA at 4 ("due to the aesthetic impacts, and perceived danger of the transmission towers and lines, negative impacts to the price of all single-family residents could range between a 15% to 18% reduction in sales price. This projected decline in sale price is based on a July 22, 2015 market study prepared by The Concord Group.")

[90] *See* Dukett FEIA at 6-10 (impacts to residential, commercial/retail, industrial/business park).

First, the negative impacts predicted by Mr. Dukett's FEIA are all fundamentally premised on the assumption that the construction of overhead transmission lines has a negative impact on property values. Purporting to rely on a 2015 study by the Concord Group and the uncorroborated testimony of a member of Hope for the Hills as part of the Tehachapi Renewable Transmission Project (A.07-06-031) proceeding, Mr. Dukett alleges a "15% to 18%" depreciation in property values due to proximity to overhead high voltage transmission lines.[92] In contrast, much larger studies are already published and reliance on the Concord Report's conclusions would mean ignoring decades of research which finds precisely the opposite:

> The research into the effects of for [High Voltage Overhead Transmission Lines (HVOTLs)] on property values is a mature area of research and has been extensively reviewed, … the actual negative effects reported in the literature are either small or negligible. Survey-based research between the late 1960s and 2010 finds persistent adverse perceptions of HVOTLs, primarily because of perceived health risks and aesthetic concerns. However, negative perceptions held by market participants did not necessarily translate into observable price differences. Though mixed, most of the statistical research before 2010 concludes that properties near HVOTLs generally do not show a significant negative impact on value and that any observed impacts diminish with distance from the lines. …

Continued from the previous page

91 Notably, and contrary to his findings, Mr. Dukett offers various potential rationales for the City's financial woes having nothing to do with RTRP, including "state legislation redirecting Vehicle License Fee revenues, rapidly rising public safety contract costs, and a sluggish economic recovery." *See* Dukett FEIA at 1.

92 *See* Dukett FEIA at 4 ("…15% to 18% reduction in sales price. This projected decline in sale price is based on a July 22, 2015 market study prepared by The Concord Group"), 22-23 (citing uncorroborated testimony offered on April 14, 2012 by Robert Goodwin (President of Hope for the Hills) alleging TRTP's impact on single family home sales in Chino Hills was 17.2%). SCE notes the cited Concord Group Report is not attached to Mr. Dukett's analysis and does not appear to be otherwise in the record of this proceeding.

> the most recent conclusions remain the *[sic]* consistent with the literature before 2010. Survey-based research finds adverse perceptions and general dislike for [High Voltage Overhead Transmission Lines (HVOTLs)], but sales data reveals little to no diminution in prices. Stated preferences by market participants in this case generally do not translate into noticeable price effects as revealed in market data.[93]

While most research is conducted on residential properties, similar conclusions have been found with respect to commercial and industrial properties:

> While most of the literature focuses on the effects of transmission lines on residential properties, especially single-family homes, Jackson, Pitts, and Norwood study the effects on both commercial and industrial properties. … The study analyzes the effects of HVOTLs on the sale prices of commercial and industrial properties …. Results from the regression analysis do not show any significant negative effects on sale price. In fact, the effects reported are generally positive, possibly because of increased transportation access available to encumbered properties. Other property types included in this study, including office, retail, hotels, apartments, restaurants, vacant land, and other unspecified industrial properties, are analyzed with the paired sales method and no significant negative impact

[93] *See* Anderson, O and Williamson, J and Wohl, A, *The Effect of High-Voltage Overhead Transmission Lines on Property Values: A Review of the Literature Since 2010*, The Appraisal Journal, Summer 2017, at 180, 192, available here: https://www.myappraisalinstitute.org/webpac/pdf/TAJ2017/TAJ_Sum17_179-193_PR-Transmission.pdf?_ga=2.127352584.421666029.1565579555-2073453443.1565373305 (last checked August 15, 2019), included here as Attachment IV-7; *see also* Jackson, Pitts, and Norwood, *The Effects of High Voltage Electric Transmission Lines on Commercial and Industrial Properties* (April 19, 2012), available here: https://www.ccimef.org/pdf/2012-298.The-Effects-of-High-Voltage-Electric-Transmission-Lines-on-Commercial-and-Industrial-Properties.4-19-12.pdf (last checked August 15, 2019), included here as Attachment IV-8; Jackson, T and Pitts, J*, The Effects of Transmission Lines on Property Values: A Literature Review",* Journal of Real Estate Literature, Vol 18, No2, 2010, 239-260, available here: http://www.atc-projects.com/wp-content/uploads/2017/04/Effects-of-Electric-Transmission-Lines-on-Property.pdf (last checked August 15, 2019), included here as Attachment IV-9.

> is found. These results are consistent with the findings of face-to-face and phone interviews with the parties involved in the transactions.[94]

Our own research at Mason & Mason has concluded similarly.[95] There is ample research to indicate that Mr. Dukett's testimony on this subject is lacking in foundation and is therefore not credible.

Second, Mr. Dukett expressly assumed that all development pursuant to the applicable specific plan will be forthcoming and developed by or before 2028.[96] This assumption ignores various facts suggesting that development has not occurred along the I-15 corridor in the City of Jurupa Valley for reasons independent from RTRP. For example, full development along the I-15 corridor has not occurred, despite the fact that Specific Plan 266 has been in effect since on or about 1992.[97]

Whether any of the development assumed by Mr. Dukett is currently planned is unknown. I am aware of no evidence in this proceeding documenting the specific intent to construct any one of the projects enumerated by Mr. Dukett as the subject of the FEIA's losses. The FEIA assumes construction of these projects will "begin during Year 1 and be completed by Year 10 (FY 2018-19 through FY 2027-28),"[98] but there is no evidence that any such construction has begun or will anytime soon. An example of such a claim in Mr. Dukett's FEIA is the loss of an allegedly planned hotel, as well as accompanying loss of transit occupancy tax associated with this hotel, when there is no evidence that considered plans for such a development even exist. Counter-factually, the Vernola Apartment Project (VAP) - the only property with confirmed entitlements along RTRP's route and adjacent to which SCE has proposed

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[94] *See id.* at 181-82.

[95] *See* Mason & Mason, Real Estate Appraisers & Consultants, *Revised 2004 to 2007 Proximity Study, Supplemental 2004 to 2008 Proximity Study, High Voltage Transmission Corridors* (May 15, 2009), included here as Attachment IV-10.

[96] *See* Dukett FEIA at 16 ("The Project Area's projected 10-Yr Max B-OH for residential uses assumed that construction (without the RTRP) would begin during Year 1 and be completed by Year 10 (FY 2018-19 through FY 2027-28).")

[97] *See* Feb. 9, 2016 Correspondence from D. Cosgrove to J. Uchida, Exhibit C & E (describing the purported evolution and status of Specific Plan 266), included here as Attachment IV-11.

[98] *See* Dukett FEIA at 16 ("The Project Area's projected 10-Yr Max B-OH for residential uses assumed that construction (without the RTRP) would begin during Year 1 and be completed by Year 10 (FY 2018-19 through FY 2027-28).")

underground construction of RTRP - remains in the same, undeveloped condition it was in 2016.[99] There is no basis to conclude that the projects envisioned by Mr. Dukett are forthcoming when even the entitled VAP has not begun construction.

Even presuming construction as Mr. Dukett envisions actively being executed, the FEIA presumes a significant degree of incompatibility between overhead transmission lines and commercial/industrial development that is undercut by evidence in SCE's own service territory. A variety of commercial, industrial, and mixed-use development coexists with overhead transmission lines in numerous instances throughout SCE's service territory.[100]

Third, there are a variety of inconsistencies in the FEIA's assertions. For example, citing undisclosed evidence from the "HdL Companies," Mr. Duckett's FEIA asserts that as of October 2018, "the City has a deficit of over 4,200 jobs and has the highest unemployment rate (5.0%) in the region."[101] The FEIA alleges Riverside County to have an unemployment rate of 4.6% in October 2018.[102] Yet, as shown in Figures 1 and 2 below, data from the U.S. Bureau of Labor Statistics notes the

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[99] I understand a 2016 Settlement Agreement among the parties agreed to the partial undergrounding of RTRP adjacent to the Vernola Apartments Project. This partial undergrounding formed the basis for SCE's currently proposed Hybrid Alternative. *See Agreement Addressing a "Hybrid" Alternative in the Riverside Transmission Reliability Project Proceeding* between the so-called "VAP Parties," the City of Riverside, and Southern California Edison Co. (Aug. 1, 2016) ("Settlement Agreement"), included here as Attachment IV-12.

[100] *See* Photos of Overhead SCE Transmission Lines near commercial developments, included as Attachment IV-13.

[101] *See* Dukett Test at 6; Dukett FEIA at 12.

[102] *See* Dukett Test at 6; Dukett FEIA at 12.

<u>Figure 4-1</u> - Jurupa Valley Unemployment Rate

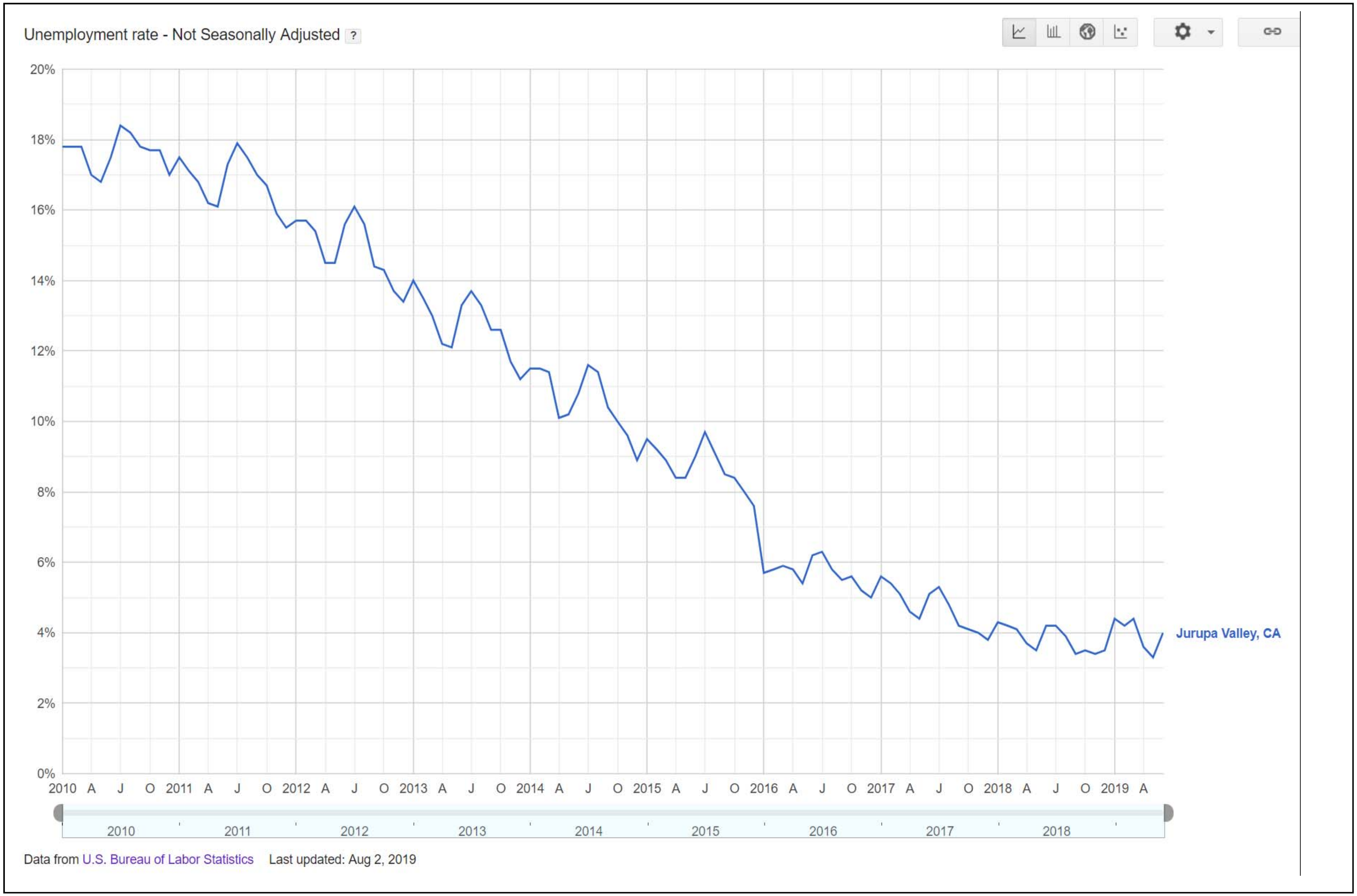
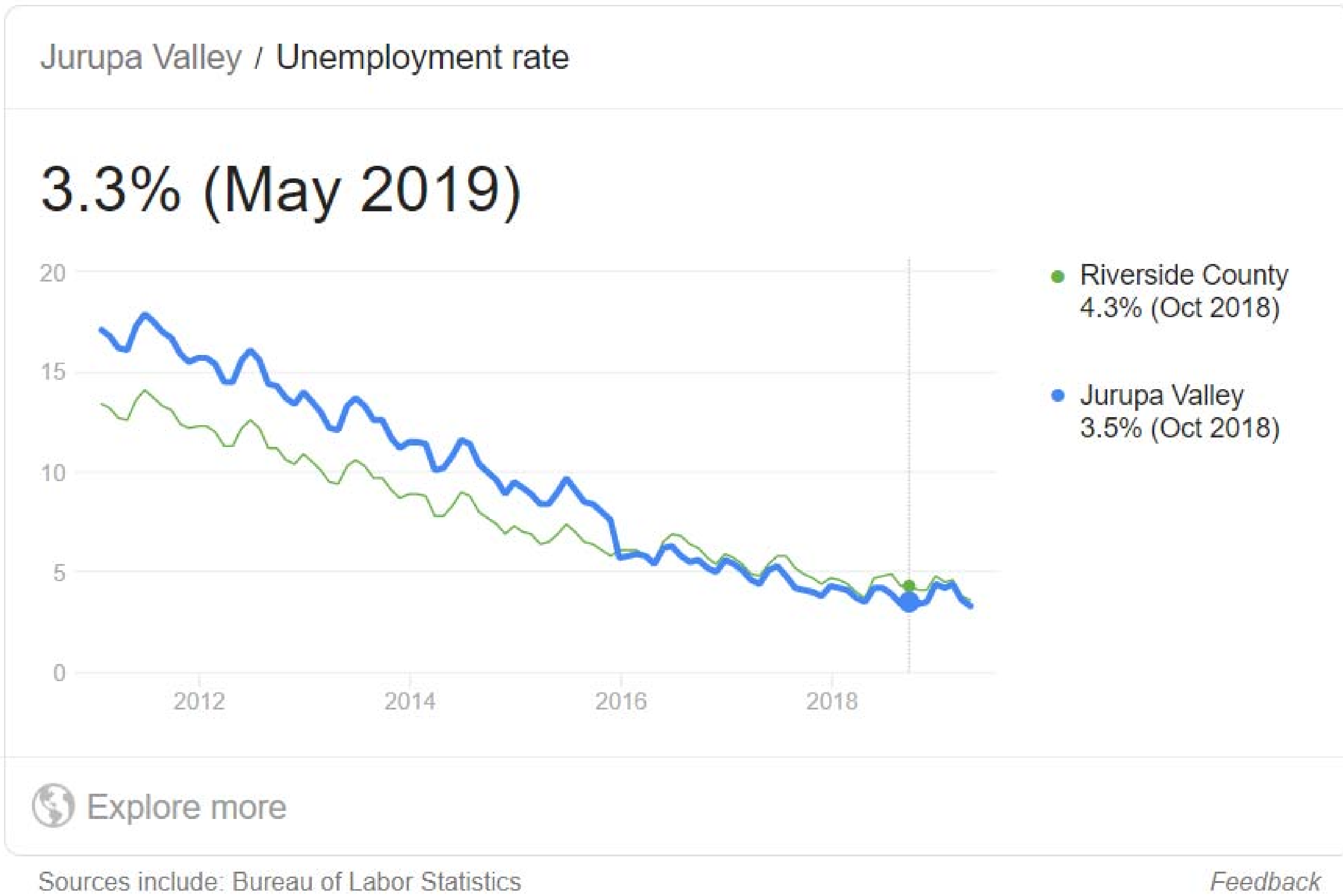
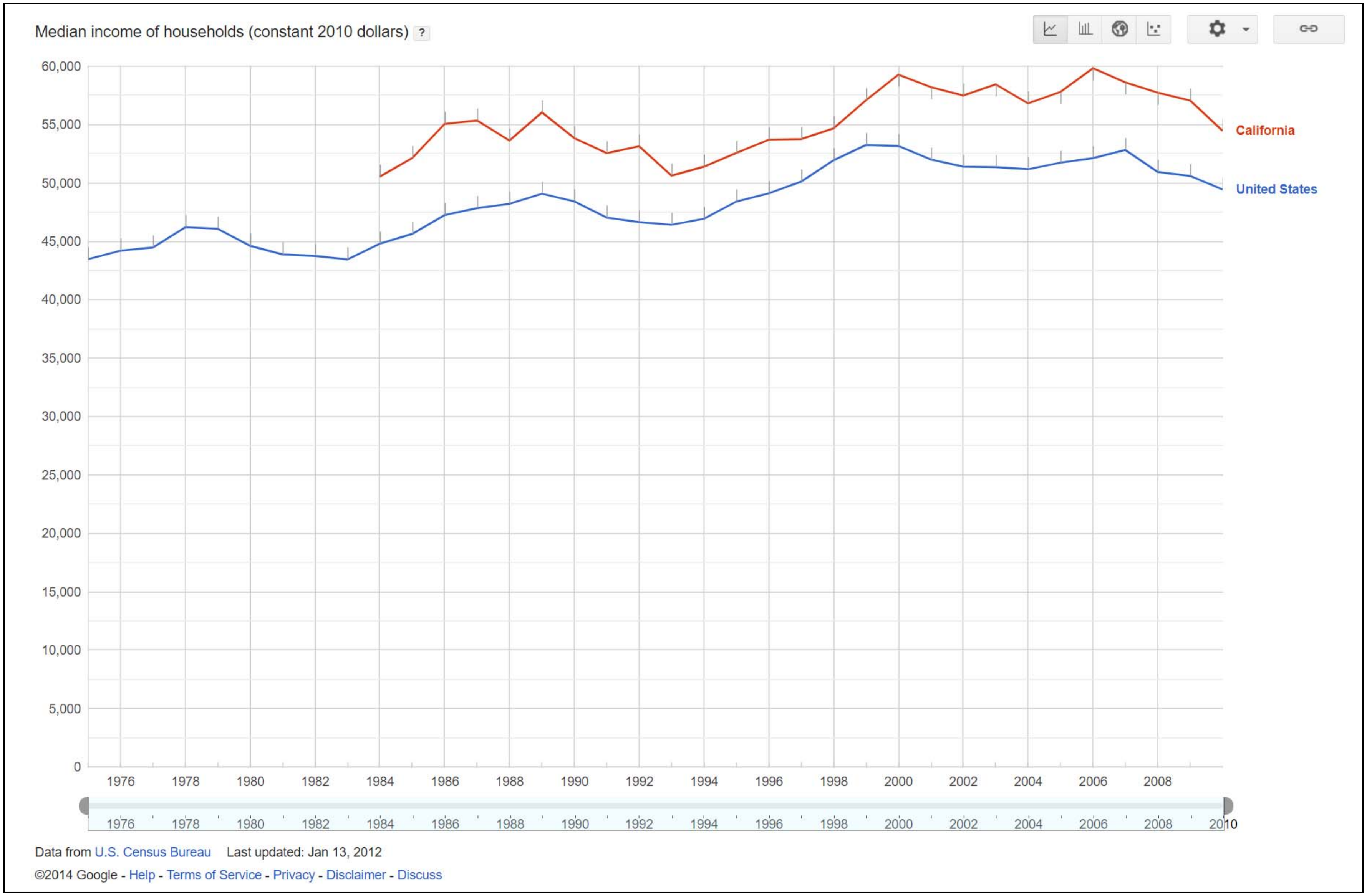


Figure 4-2 - **Riverside County and Jurupa Valley Unemployment Rates**



<u>Figure 4-3</u> - Median Income of Households (California and the United States)



unemployment rate in Jurupa Valley is 3.5% in October 2018 (3.3% as of May 2019).[103] Thus, Jurupa Valley's unemployment levels are actually superior to Riverside County's according to the U.S. Bureau of Labor Statistics.

Another potential discrepancy is Mr. Dukett's presentation of income data. Mr. Dukett asserts "[t]he income per capita in the City is $20,390, which is lower than the national average ($31,177) and lower than the California average ($33,128)."[104] This manner to present household income would presumably be affected by the number of persons assumed in each household. The more children in a household for example, the lower this "income per capita" number would be. Further, Mr. Dukett's suggestion that Jurupa Valley is somehow worse off as compared against the median household incomes in California and the United States seems contrary to data from the U.S. Census. As of 2010, the last census date, the median household income in Jurupa Valley was $63,286.[105] As shown in Figure 4-3 above, the median household income in California was $54,459 and the United States averaged $49,445.[106] Again, contrary to Mr. Dukett's suggestion, Jurupa Valley compares favorably to both California and the United States in terms of median household income according to the U.S. Census.

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

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[103] *See* Google Public Data search page (referencing U.S. Bureau of Labor Statistics data), available here: https://www.google.com/publicdata/explore?ds=z1ebjpgk2654c1_&met_y=unemployment_rate&idim=city:CT0637692000000&fdim_y=seasonality:U&hl=en&dl=en (last checked August 15, 2019).

[104] *See* Dukett FEIA at 8.

[105] *See* U.S. Census Website, Jurupa Valley webpage, available here: https://www.census.gov/quickfacts/fact/table/jurupavalleycitycalifornia/PST045218 (last checked August 15, 2019), a true and exact copy of which is included as Attachment IV-14.

[106] *See* Google Public Data search page (referencing U.S. Census data), available here: https://www.google.com/publicdata/explore?ds=c8op9mhgodplq_&ctype=l&met_y=median_income_constant&hl=en&dl=en#!ctype=l&strail=false&bcs=d&nselm=h&met_y=median_income_constant&scale_y=lin&ind_y=false&rdim=country&idim=state:CA&idim=country:US&ifdim=country&hl=en_US&dl=en&ind=false (last checked August 15, 2019).

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.

V.

SCE's Rebuttal Testimony Regarding The Maximum Prudent And Reasonable Cost Of RTRP And The Estimated Cost Of The Project Alternatives And The Qualifications Of Kathy Hidalgo[107]

Q: ***Please state your name and business address for the record.***

A: My name is Kathy Hidalgo, and my business address is 2 Innovation Way, Pomona, California.

Q: ***Briefly describe your education, work history and present responsibilities at SCE.***

A: I received my Bachelor's Degree in electrical engineering from Virginia Polytechnic Institute and State University and my Master's Degree in business administration from the University of Maryland at College Park. In addition, I hold a Project Management Professional credential from Project Management Institute. My professional background includes over six years of service in project management organizations at SCE and over 20 years of experience in engineering, technical and project management, business process management, and project controls with various aerospace and defense companies. I am responsible for managing the project cost control team for major projects and transmission and substation projects.

Q: ***Please describe your role with respect to the RTRP.***

A: I am a Principal Manager in the Major Projects Organization within SCE's Transmission and Distribution Operating Unit. My responsibilities include the oversight and management of project and strategic controls functions including the development, management, and reporting of major project and program estimates, schedules, and total costs throughout the project and program lifecycles.

Q: ***What is the purpose of your testimony in this proceeding?***

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Rebuttal Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to: (a) the

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[107] This Section responds to Intervenor Direct Testimony and addresses Scoping Memo Issues ## 5 ("*Are the mitigation measures or project alternatives infeasible? This issue encompasses consideration of community values pursuant to Pub. Util. Code § 1002(a)(1)*") and 8 ("*What is the maximum prudent and reasonable cost of the project? (See Pub. Util. Code § 1005.5.)*").

estimated cost to construct RTRP and the *Testimony Of Marcor Platt On Behalf Of Sky Country Investment Co./East LLC* (the "Platt Testimony ") and others related thereto; (b) the Franchise Agreement with the City of Jurupa Valley and "known risk" of an unsupportive local government; and (c) suggestions that the costs of RTRP are inconsistent with applicable tariffs or will otherwise cost more than SCE estimates. In support of this testimony, I reviewed portions of the *Testimony Of Marcor Platt On Behalf Of Sky Country Investment Co./East LLC* ("Platt Testimony"), *Public Advocates Office Prepared Testimony regarding RTRP* ("Cal Advocates' Testimony"), *and Direct Testimony of Gary Thompson on Behalf of the City of Jurupa Valley* ("Thompson Testimony").

Q: *Do you think the cost estimates of Mr. Platt are more likely to be accurate than SCE's and if not, why not?*

A: No, I do not think Mr. Platt's testimony with respect to the estimated maximum reasonable and prudent cost for either the Hybrid Alternative or Alternative 1 are more accurate than SCE's estimates. Mr. Platt's estimates are flawed and based on unsupported assumptions. In light of these facts, Mr. Platt's estimates differed from SCE's estimates in numerous areas.

With respect to SCE's real properties estimates, supported by the testimony of others, Mr. Platt suggests that SCE has underestimated the likely real properties acquisition costs associated with the Hybrid Alternative by approximately $94.8M.[108] Conversely, Mr. Platt suggests that SCE has overestimated the likely costs of the construction of the Hybrid Alternative and Alternative 1 by approximately $59.9M and $89.9M, respectively.[109] The most significant discrepancies are summarized in Table 5-1 as follows:

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[108] *See* Platt Errata at 11, Tbl. 1 (real properties cost differential asserted to be $94.8M). Real Properties acquisition discrepancies are discussed in Section IV above.

[109] *See* Platt Errata at 11, Tbl. 1 [redacted]), 12, Tbl. 2 ([redacted])

Table 5-1 - ***Platt Testimony vs. SCE Testimony, Significant Cost Variance***[110]

[redacted]

[110] The numbers in red reflect the discrepancies between Mr. Platt's and SCE's asserted construction costs, excluding real properties acquisition costs which are discussed in Section IV above. For example, Mr. Platt believes the cable vendor/cost (row 1 above) for the Hybrid Alternative will actually be [redacted] less than SCE's estimate. That difference reflects 37% of the total cost difference between SCE's estimates and Mr. Platt's estimates.

While Mr. Platt's testimony asserts that the Hybrid Alternative and Alternative 1 will respectively cost $59.9M and $89.9M less to construct than SCE estimates (*see* Platt Errata at 11 and 12), SCE has not verified his totals. SCE notes that it has corrected the asserted difference in sales tax attributable to the Hybrid Alternative as [redacted] (in lieu of [redacted] as asserted in Platt Errata, Appx. B-2). Mr. Platt appears to have asserted sales tax to be [redacted] (the Alt. 1 figure, *see* Platt Errata, Appx. B-2) when SCE asserted it to be [redacted] (*see* SCE Direct Testimony, Attachment O at O-76). *See also* Platt Donan Rpt. at 24, Tbl. 5 (summarizing "known risk price reduction").

Hard digging and *Vault Count/Size* are primarily based on engineering scope discrepancies and are therefore discussed in the testimony of Roman Vasquez in Section VI below.

On the basis of these simultaneous over and underestimates, Mr. Platt suggests that the Hybrid Alternative will cost $442.9M, and Alternative 1 will cost $431.8M (a difference of $11.1M).[111] Mr. Platt's estimates posit that the totality of discrepancies suggests Alternative 1, which includes 4 miles of 220 kV underground, will actually be a *less* expensive project than the Hybrid Alternative, which includes 2 miles of 220 kV underground. I respectfully disagree.

A. Mr. Platt's Assertions that SCE's Estimated Costs Are Excessive Are Based on Methodological Flaws and Assumptions Unsupported By RTRP's Facts

As a threshold matter, serious flaws, misclassifications and underestimates generally undermine the credibility and inherent reliability of Mr. Platt's cost estimates. First, Mr. Platt purportedly used materials costs from three separate vendors, but used the labor costs that SCE designated in Attachment O of its direct testimony. This is, however, not a realistic approach. Neither RTRP, nor any project would be constructed in this manner for several reasons, including:

- SCE would require that the underground cable system be demonstrably safe and reliable, requiring an exemplar of the cable system be made available for testing and quality assurance/quality control (QA/QC) – in SCE's experience, no group of separate vendors have ever collaborated to offer such a work product;
- SCE is aware of no previous examples of a group of disparate vendors providing binding bids contingent over a period of multiple years pending successful completion of QA/QC that depends on the actions and responses of other vendors outside of their control;
- When services are procured from various vendors, each providing disparate parts or labor in support of any cable system, economies of scale are lost and project management costs generally increase, suggesting that Mr. Platt's approach would prove more expensive in practice than SCE's; and
- Given the necessary interconnection of the disparate elements of the cable system, it would be unlikely that vendors offer the desired warranties guaranteeing the proper functioning of the cable

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[111] *See* Platt Errata at 11, 12.

system and even if such warranties were offered, they would be exceedingly complicated to enforce in the event of a cable system failure or delays in implementation.

Further, as referenced above, Mr. Platt's estimates are unreliable because he appears to have relied on non-binding quotes from sources in support of their estimated material prices.[112] The quotes used, provided with limited or documentation, come with no guarantees, no schedule and are subject to change. Cost estimates built upon these non-binding quotes are inherently unreliable.

In contrast, SCE's estimates are derived from actual project experience constructing underground transmission lines. SCE's base costs for material and labor for RTRP are derived principally from its experience on the Tehachapi Renewable Transmission Project ("TRTP").[113] As SCE explained in response to numerous data requests

> SCE's Cost Workpapers derived the Project support costs by multiplying the monthly "burn rate" experienced during the underground construction of TRTP by the estimated construction durations for those Alternatives. The TRTP underground construction monthly burn rate can be generally

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[112] *See Response of Sky Country Investments Co./East LLP to Question 3 of the First Data Request of the Southern California Edison Company*, included here as Attachment V-1 (*e.g*., Prysmian quote is "budgetary" and "subject to…actual project requirements and specifications" and "Actual Purchase pricing with binding terms may be provided upon our response to an actual Request for Offer"; Southwire estimates are "rough numbers;" and Mr. Douglas Proctor's correspondence with Mr. Platt notes "The prices to date were for 5000 kcmil 230-kV XLPE Cable only. Although the number of prices received do no constitute a meaningful data set, the Southwire pricing was $120/ft, SCE prices were $155/ft, and Prysmian (General Cable) pricing was $103/ft. The average price was $126. The SCE price is 29% over the average price, the Prysmian price was 18% below the average price, and the Southwire price was 5% below the average. The cable vendors contacted indicated that 230-kV cable prices vary over time with copper prices, which can be tracked on the London Exchange. Prices for 5000 kcmil 230-kV XLPE cable were also obtained in August of 2017 for BC Hydro. The price from Southwire at that time was $143.79/ft."); *Response of Sky Country Investments Co./East LLP to Third Data Request of the Southern California Edison Company*, included here as Attachment V-2 (Southwire quote of $143.79/ft. was the only binding quote noted (30 days) but was not used by Mr. Platt).

[113] *See* SCE *Cost Estimating Material Takeoff, Lennar Hybrid* (Jan., 2016)(approximating Hybrid Alternative, included here as Attachment V-3) (showing workpaper estimates with notes reflecting certain links between TRTP and RTRP); SCE *Cost Estimating Material Takeoff, Pats Ranch Road* (Aug., 2015)(Approximating Alternative 1, included here as Attachment V-4 (showing workpaper estimates with notes reflecting certain links between TRTP and RTRP)*; see also Southern California Edison Company's (U 338-E) Petition for Modification of Decisions 09-12-044, 13-07-018, and 14-01-005* (A.07-06-031) (January 18, 2017), available here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K518/172518962.PDF (last checked August 15, 2019).

derived by taking the total costs of construction and dividing by the number of months that construction took to complete.[114]

Various cost components used for RTRP's cost estimates were based directly on the underground portion of TRTP, escalated to account for inflation and adjusted to the construction scope and duration of RTRP.[115]

1. SCE's estimated cable costs are based on actual bids and more likely to be accurate than non-binding quotes and theoretical assumptions [116]

Mr. Platt believes the cable cost for the Hybrid Alternative will be [redacted] less than SCE's estimate of [redacted] Mr. Platt believes the cable cost for the Alternative One will be [redacted] less than SCE's estimate of [redacted] Excluding real properties acquisition, the cable costs represent 37% and 39% of the total difference in estimated costs between Mr. Platt's estimates and SCE's estimates for the Hybrid and Alternative 1, respectively.[117]

a) Cable Vendor Unavailability Risk[118]

As identified in SCE's cost estimated in Attachment O of its direct testimony, the relatively limited number of vendors for underground 220 kV cable is considered to be a "known risk."[119] Mr. Platt discounts the cost associated with this risk. SCE quantified this known risk as [redacted] for the

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[114] *See* SCE Response to Gateway Properties Parties Data Request Verbal 001 (5/14/19), included as Attachment V-5.

[115] *See* SCE Response to Gateway Properties Parties Data Request 3.14 (3/29/19), included as Attachment V-6.

[116] As used herein, "cable" refers to *underground* cable, whereas *aboveground* facilities are referred to as "conductor."

[117] *See* Table 5-1, *supra*.

[118] This "known risk" reflects the chance that SCE's preferred cable system contractor is not available. Under that circumstance, SCE may need to contract with a less economical contractor.

[119] *See* SCE Direct Testimony, Attachment O at O-272 ("Vendor availability is limited for Underground 220kV cable"), O-278 (*ibid.*).

Hybrid Alternative and $[redacted] for Alternative 1,[120] whereas Mr. Platt quantified this known risk as $3,750,000 for the Hybrid Alternative and $7,340,000 for Alternative 1.[121]

In developing his estimate and justifying the reduction of cost here, Mr. Platt first assumes that the number of cable vendors and availability of 220 kV cable mirrors the number of vendors and availability of the primary commodity making up the cable – copper.[122] Having made this logical leap, Mr. Platt employ a quantitative probability method and assume the number of vendors for cable systems follows a "bell-curve" distribution, in an attempt to project that what the cable system "should" cost.[123]

This approach is fundamentally flawed as it does not reflect the actual market for cable systems or the number of available vendors of same. First, the cable systems needed for the bulk (200 kV and up) transmission of power underground are complex, engineered products that are produced to order. The costs for cable systems not only include the cost of the raw materials, but also labor for splices, terminations, research and development, project management, *etc*. The cable systems needed for the safe and reliable transmission of power are not analogous to "commodities," which are raw materials, interchangeable with other commodities of the same type, and used to manufacture finished goods.[124]

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[120] *See* SCE Direct Testimony, Attachment O at O-272, O-278.

[121] *See* Platt Testimony at 9:13-15 ("SCE overestimated the costs associated with Limited Vendor Availability risk. This reduction results in lowering the Alternative 1 cost by $18.3 million, and the Hybrid Alternative cost by $8.7 million"); Platt Donan Rpt. at 24, Tbl. 5 ($3.75M for Hybrid and $7.34M for Alternative 1).

[122] *See* Platt Donan Rpt. at 22, fn. 18 ("The analysis assumes that the price of cables follows a normal distribution, which is reasonable since the price of cables is driven mainly by the price of copper, which follows a normal distribution.")

[123] *See* Platt Donan Rpt. at 22, fn. 18 ("normal distribution"). Notably, Mr. Platt omits one of the few quotes he received - the 2017 Southwire cable cost of $143.70/foot (the only quote which was binding for any length of time (30 days) - in his calculation of his allegedly average cable cost. *See* fn. 113, *supra (citing* Attachments V-2 & V-3 hereto).

[124] For example, for Alternative 1 SCE generally assumed $[redacted] for cable material, [redacted] sales tax, [redacted] for cable labor, for a total of $[redacted] *See* SCE Direct Testimony, Attachment O. Copper weighs approximately 16.3 lbs./ ft. Assuming a cost for copper of $2.75/ lb. (or approximately $45/ft. of copper), SCE estimates that Alt 1 will require approximately 297,832 ft. of cable at a cost of $13.4M in copper cost alone. However, this would make the price of copper only [redacted] of the cost of our estimated Alternative 1 cable system. In contrast to Mr. Platt's testimony, SCE estimates that the other [redacted] of the cable system will have a large role in driving the total cable system cost, beyond that of the price of copper.

Further, manifestly unlike commodities, the market for cable systems and cable vendors is small and not random - there are only a few vendors qualified to manufacture and install these specialized cable systems. Thus, Mr. Platt's assumption that the market and price distribution for cable systems follows that of copper is an inappropriate and flawed basis to criticize SCE's cost estimate for this risk.

In contrast to Mr. Platt's theoretical approach, SCE's estimated risk value associated with cable vendor availability is based on the actual bids received for the underground portion of TRTP. There, in response to SCE's articulated scope of construction, terms and conditions, and schedule, SCE received bids from five cable vendors. Two bids were eliminated during SCE's technical review. The three bids left for commercial review were all 180-days binding and included a not-to-exceed total material and labor cost for the cable systems supported by a two-year warranty. Of these three bids, [redacted] was considerably more in total cost than the most economical, winning vendor.[125]

In turn, RTRP's cost estimates for its cable system were based on the winning TRTP bidder's actual (most economical) total bid cost from TRTP undergrounding work, with prices updated by that same bidder in 2018. SCE estimated that if the cost risk associated with "*Vendor availability is limited for Underground 220kV cable*" (*i.e.*, the cost risk that would befall SCE if it were forced (due to limited vendor bids or other) to go with the bid of a more expensive vendor, *e.g.* [redacted]) were added to its RTRP cost estimate, then the total cable system cost could be increased by as much as the percentage difference between the winning (most economical) and the highest (least economical) TRTP bids.[126] This total known risk cost was then multiplied by a probability factor (in this case 20%), to derive the estimated known risk value ultimately used in SCE's cost estimates – approximately \$17M.[127]

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[125] *See* SCE TRTP Segment 8, Chino Hills 500kV Underground Cable Project, Specification No. E-2012-65, XLPE Cable Systems (Furnish & Install), RFP Issue, 21-NOV-2012, Rev Bid 1, *Table 1.1 - Lump Sum Price Quotation Form (Option A) (Circuit 1 with 2 cables per phase)* completed by [redacted] included as Attachment V-6 (Prysmian bidding [redacted]

[126] *See* SCE Response to Gateway Properties Parties Data Requests 7.3(a), 7.4(a), 12.3(a) and 12.3(b) (included as Attachment V-7) ("The dollar amount specified for each 'Known Risk' in Attachment O represents the anticipated costs that risk involves, multiplied by a probability (less than 100%) the risk will be realized").

[127] *See id.;* SCE Direct Testimony, Attachment O at O-272 [redacted] O-278 [redacted]

As it is based on actual bids, recently received, in support of an SCE project in the same geographic vicinity and of the same general type (underground construction), SCE's estimated risk associated with vendor availability is more likely to be accurate than the theoretical basis upon which Mr. Platt's estimates are based.

b) Cable Material Costs

SCE estimates the cost of the 5,000 CU kcmil XLPE cable as $[redacted].,[128] whereas Mr. Platt estimates the cost of cable as $103.73/ ft.[129]

The quotes used to derive Mr. Platt's estimates are suspect and unreliable. Mr. Platt's estimate of $103.73/ft. is purportedly based on a quote received from Prysmian. It is clear that there was no engineering specifications, contractual terms and conditions, schedule, and/or warranties supported Prysmian's quote, and it was not a binding quote. Notably, Prysmian was the highest bidder for the TRTP underground work. There, as part of TRTP's underground binding construction bid process, Prysmian bid [redacted]. for 5,000 CU kcmil XLPE cable.[130]

Further, Mr. Platt did not change any construction labor unit costs in support of their cost estimates, *i.e.*, they assumed the material for the cable system could be provided by three different manufacturers, but the labor for installation of that cable system could be provided by the vendor (and that vendor's price) SCE noted. This theoretical "cherry picking" of the lowest cost components from a variety of bids from different vendors is inconsistent with actual practice, as well as the California Public Utilities Code section 1001's guiding principles with respect to deriving the estimate of maximum prudent and reasonable cost in support of a CPCN.

As noted previously, SCE is not in the market for copper cable but rather a cable system. SCE requires that cable system be safe, reliable, and supported by warranty and binding bids guaranteeing the

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[128] *See* SCE Direct Testimony, Attachment O at O-75 (Hybrid Alternative [redacted] * 153,925 ft. of cable for a total cost of [redacted] O-97 (Alternative 1, [redacted]. * 297,832 ft. for a total cost of [redacted]).

[129] *See* Platt Donan Rpt. at 22 (Southwire $120.00/ft., Prysmian at $103.73/ft.).

[130] *See* Attachment V-6 (Prysmian bidding [redacted]

lowest total economic cost. Mr. Platt's estimates are unfortunately lacking in those qualities and thus are less likely to be accurate than SCE's estimates.

2. SCE appropriately applied contingency to its known risk costs

Mr. Platt believes the contingency/management reserve for the Hybrid Alternative and Alternative 1 should be $0. SCE estimated the contingency/management reserve as $[redacted] for the Hybrid Alternative and $[redacted] for Alternative 1. Excluding real properties acquisition, the contingency/management reserve costs represent 16% and 14% of the total difference in estimated costs between Mr. Platt's estimates and SCE's estimates for the Hybrid and Alternative 1, respectively.

Mr. Platt correctly notes that "[u]sing a cost-impact approach, SCE developed the known risk costs by applying a probability to an expected cost impact. This is also consistent with an expected monetary value (EMV) approach, as defined by the PMI."[131] Unfortunately, and contrary to SCE's data request responses, Mr. Platt then erroneously concludes

> [a]s such, the known risks make up a contingency reserve … [t]he uncertainty of the risk is therefore accounted for in the known risk cost. … By increasing the known risks by 15% and including that increase as a Contingency Reserve, SCE is creating a contingency upon a contingency. This is not consistent with the EMV approach, does not improve the estimate, and is irrational.[132]

On this basis, Mr. Platt recommends

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[131] *See* Platt Donan Rpt. at 9-10 ("The EMV approach is a rational approach for assigning a value to known-unknowns. In the EMV approach, any uncertainty with a known risk is accounted for with the probability number, which is multiplied by the expected value should the risk occur to produce the known risk cost. The uncertainty of the risk is therefore accounted for in the known risk cost.").

[132] *See* Platt Donan Rpt. at 10 ("The DT Table 2 15% increase is applied to all other direct costs as well as to known risks. Because it is applied across the board, the 15% increase was not specially developed for known risks. From that standpoint, it is arbitrary. The arbitrary increase therefore does not account for any additional uncertainty. Applying an arbitrary increase to values developed using a rational approach does not improve the accuracy of the estimate, and negates any value gained by applying a rational approach. By increasing the known risks by 15% and including that increase as a Contingency Reserve, SCE is creating a contingency upon a contingency. This is not consistent with the EMV approach, does not improve the estimate, and is irrational.").

> The 15% increase associated with direct costs should be classified as Activity Contingency Reserves, and the activities plus the Activity Contingency Reserve should make up the work package cost estimate. The known risks should be classified as Contingency Reserves, and not as Activity Contingency Reserves. I therefore recommend removing the 15% contingency applied to SCE's known risk costs for both Alternative 1 and the Hybrid Alternative.[133]

Consistent with the Project Management Body of Knowledge (PMBOK) Guide, 6th Edition cited by Mr. Platt, SCE disagrees.

14.4 Figure 7-8 of the Project Management Body of Knowledge (PMBOK) Guide, 6th Edition, Section 7.3.3.1 is reproduced below:

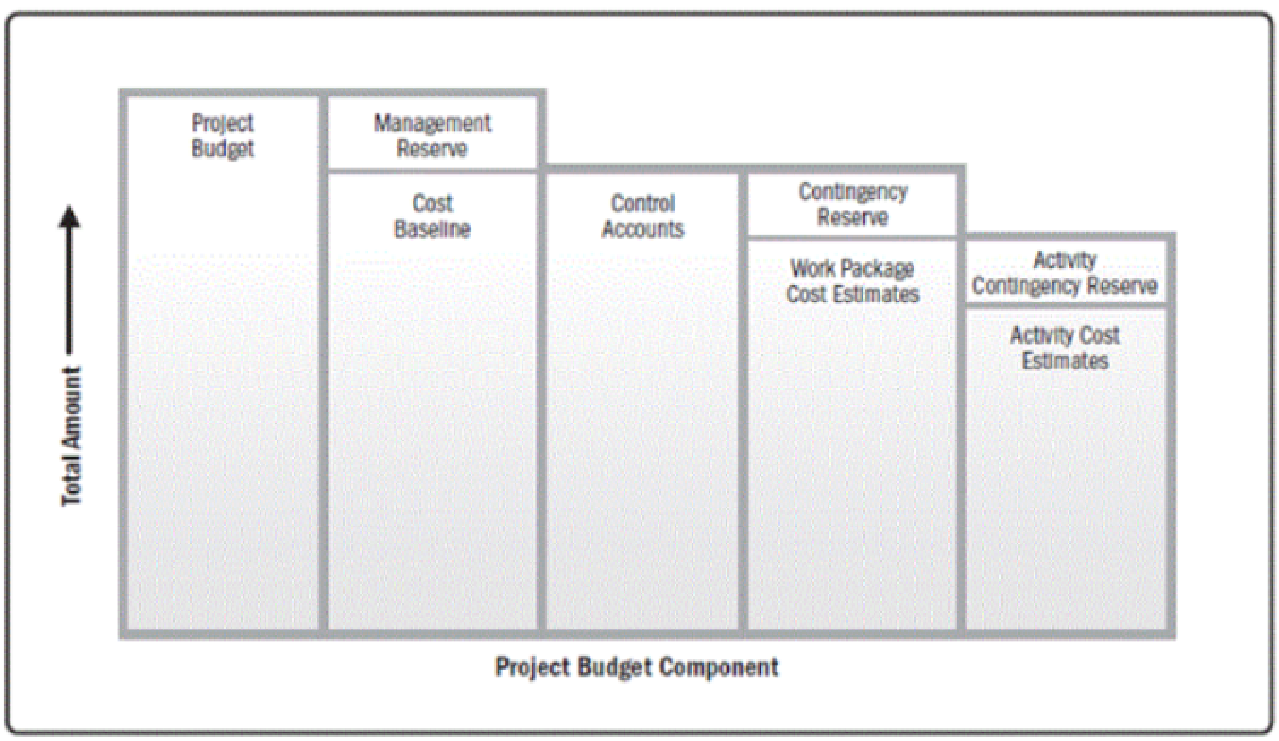

Figure 7-8. Project Budget Components

[133] *See* Platt Donan Rpt. at 10 (6.1.1.3. Recommendations).

PMBOK Figure 7-8, included in Gateway Properties Parties' data request 14.4, is reproduced above.[134] As noted in SCE's response to Gateway Properties Parties' data request 14.3 and 14.4

> SCE confirms that the "known risks" are appropriately categorized as a portion of the budget within the cost baseline that is allocated for identified risks but does not confirm the detailed categorization or naming conventions as identified by the [PMBOK]…SCE's "known risks" can be categorized as a combination of "Contingency Reserves" and "Activity Contingency Reserve."[135]

While SCE maintains that it does not endorse PMBOK's detailed categorizations or naming conventions, SCE's 15% contingency would be considered "Management Reserve" as depicted in Figure 7-8. Consistent with the application of Management Reserve against the entire cost baseline depicted in Figure 7-8, SCE's 15% contingency would be applied on all project costs, including "Known Risks," which SCE stated it would categorize "as a combination of 'Contingency Reserves' and 'Activity Contingency Reserve.'"[136] Further, despite Mr. Platt's citation to and endorsement of PMBOK Figure 7-8, he omits "Management Reserve" entirely in his estimated costs for the Hybrid Alternative and Alternative 1.[137]

Mr. Platt's arguments are inconsistent with the PMBOK he cites and "best management practices" he purports to espouse.[138]

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[134] *See* Gateway Properties Parties Data Request 14.4 and SCE Response thereto (included as Attachment V-8).

[135] *See id.;* SCE Response to Gateway Properties Parties Data Request 14.3 (included as Attachment V-9).

[136] *See* Gateway Properties Parties Data Request 14.4 and SCE Response thereto (included as Attachment V-8).

[137] *See* Platt Errata, Appx. B-1 and B-2 (applying no "management reserve").

[138] *See* Platt Testimony at 6-7 ("SCE applies a 15% increase on each Known Risk for an additional contingency … [which] misclassifies the Known Risk Category, is inconsistent with the rationale behind the development of the known risks, and is not in accordance with best management practices. As a result, I reduced the SCE's total estimated costs for Known Risks for both the Hybrid and Alternative 1 by eliminating the 15% contingency factor"), 9 ("SCE's 15% contingency increase for the known risks costs represents the imposition of a contingency upon a contingency, misclassification of the known risk category, is inconsistent with the rationale behind the development of the known risks category, and is inconsistent with best management practices. The

(*Continued*)

3. **Intervenor's estimates of sales tax are improper**

Mr. Platt believes the Sales Tax for the Hybrid Alternative will be [redacted] less than SCE's estimate of [redacted] Mr. Platt believes the Sales Tax for the Alternative One will be [redacted] less than SCE's estimate of [redacted] Excluding real properties acquisition, the Sales Tax represent 7% and 9% of the total difference in estimated costs between Mr. Platt's estimates, and SCE's estimates for the Hybrid and Alternative 1, respectively. Mr. Platt's estimates are inconsistent with applicable sales tax rates, accepted accounting principles, and good-faith estimating protocols for project budgeting.

First, Mr. Platt appears to have significantly underestimated the total costs of materials required for the construction of RTRP against which the sales tax would be applied.[139] Second, Mr. Platt appears to have compounded this error by applying a sales tax rate of 1%.[140] SCE is aware of no rational basis for the application of a 1% sales tax rate on materials purchased in support of RTRP's construction. In contrast, and based on its past project construction experience, SCE estimates a sales tax of 9.7% in order to cover the applicable sales tax in addition to shipping costs.[141]

Mr. Platt's sales tax estimates do not establish a credible basis for a reduction in anticipated construction costs of RTRP.

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SCE estimates should be reduced by $12 million for Alternative 1 and $8.8 million for the Hybrid Alternative"); Platt Donan Rpt. at 30 (*ibid.*)

[139] *See e.g.,* Platt Errata Appx. B1 (Alternative 1) at 1 (suggesting the total *materials acquisition* costs for RTRP Alternative 1 to total $2.6M, in contrast with SCE's estimated materials cost of $86.2M (*see* SCE Direct Testimony, <u>Attachment O</u> at O-98 ((Total materials cost is $[redacted]) – (Sales tax of $[redacted]) = $[redacted]))

[140] *See e.g.*, Platt Errata Appx. B1 (Alternative 1) at 1 (suggesting the total materials *sales tax* costs for RTRP Alternative to total $26.2K, in contrast with SCE's estimated [redacted] ((SCE Direct Testimony, <u>Attachment O</u> at O-98 ($[redacted])).

[141] *See* SCE Direct Testimony, <u>Attachment O</u> at O-98 (referencing a 9.7% tax rate (($[redacted]) *(9.7% tax rate) = $[redacted]).

4. <u>Intervenors estimates of "Owners Agent" costs are theoretical and are inferior to SCE's project-based estimates</u>

Mr. Platt believes SCE's contract construction management or "Owners Agent" costs for the Hybrid Alternative will be [redacted], [redacted] less than SCE's estimated costs of [redacted] Mr. Platt believes SCE's Owners Agent costs for the Alternative 1 will be $[redacted], [redacted] less than SCE's estimated costs of $[redacted]. Excluding real properties acquisition, the Owners Agent costs represent 6% and 8% of the total difference in estimated costs between Mr. Platt's estimates, and SCE's estimates for the Hybrid and Alternative 1, respectively.

Mr. Platt's estimates are speculative, based on a methodology that has only tenuous bearing on projects in California or the Owners Agent costs Mr. Platt seeks to reduce. Mr. Platt's estimates are purportedly based on a Western Area Power Administration (WAPA) methodology wherein "the management costs are equated to a percentage of the combined labor and material costs (minus major material costs such as cable)."[142] Mr. Platt asserts this WAPA methodology was employed on two projects: (1) the 340-mile 500 kV transmission line California-Oregon Transmission Project (COTP), which Mr. Platt alleges to have estimated management costs at 5%; and (2) the British Columbia Hydro 230 kV underground project (BC Hydro), which Mr. Platt alleges to have estimated management costs at 9%, as well as serving as the basis for an assumed 5% management cost within a cost estimating algorithm used by the Midwest Independent Transmission System Operator (MISO) - although it is unclear from Mr. Platt's testimony whether this MISO algorithm has ever be used on any projects.[143]

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[142] *See* Platt Donan Rpt. at 26-27 ("At my direction, Mr. Proctor provided estimated costs for the contract construction management. Per the historical-based methodology adopted by WAPA, the management costs are equated to a percentage of the combined labor and material costs (minus major material costs such as cable)"); Platt Test at 8 ("…the costs for Contract Construction Management which SCE ascribed to both the Hybrid Alternative and Alternative 1 are overestimated. … I have reduced these costs consistent with the historical-based methodology adopted by the Western Area Power Administration (WAPA) …. Per this methodology, the management costs are equated to a percentage of the labor and material costs (minus major material costs such as cable)").

[143] *See* Platt Donan Rpt. at 27 ("Projects utilizing this methodology include the following: [*] The California-Oregon Transmission Project (COTP), which is a 340-mile 500 kV transmission line. For the COTP project, 5% of the total labor and material costs (minus major costs) was used to estimate management costs, and the final

(*Continued*)

Mr. Platt's purports to apply WAPA's methodology, assuming SCE's Owner's Agent costs should be "10% of the total labor and material costs (minus major costs)."[144]

First, the WAPA methodology as described and cited by Mr. Platt is incredibly opaque, variable, and subject to manipulation. Even among the three examples cited in Mr. Platt's testimony, the percentage of estimated costs ranged from 5% to 9%, with no rational basis cited to discern which percentage is most appropriate.[145] Also, Mr. Platt is unable to support his argument with actual cost numbers, he only offers estimated numbers. Further, the proper scope of "major material costs" that should be excluded from the labor and material costs in WAPA's calculation seems without rational justification. Here, Mr. Platt suggests (although it is not clear) that he has only excluded cable costs, but there is no basis offered for that election.[146] In addition, the relevance of the WAPA methodology to Owners Agent costs as opposed to "management costs" is questionable – there is no basis or rationale offered justifying why WAPA's methodologies regarding "management costs" should be applicable to

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construction cost was within 2.5% of the original planning estimate amount. [*] The British Columbia Hydro (BC-Hydro) 230 kV underground project, which used 5000 kcmil 230 kV XLPE cable. For the BC-Hydro project, 9% of the total labor and material costs (minus major costs) was used to estimate management costs. [*] A cost estimating algorithm based on this methodology was prepared by Proctor Engineering, Inc. and Bates-White, Inc. for use by members of the Midwest Independent Transmission System Operator (MISO) to prepare planning estimates to evaluate new or upgrade transmission and substation projects. For the MISO project, 5% of the total labor and material costs (minus major costs) was used to estimate management costs.") SCE understands that the COTP was purportedly completed 26 years ago in 1993, but the BC Hydro Project has been placed indefinitely on hold.

[144] *See* Platt Donan Rpt. at 27 ("SCE's estimate for contract construction management was approximately 14.5% of the total material costs, excluding cable costs, plus the craft labor costs for Alternative 1, and 13% for the Hybrid Alternative. Based on the management pricing, the contract construction management cost was approximately $5.6 million less than SCE's cost for Alternative 1, and approximately $3.5 million less than SCE's cost for the Hybrid Alternative"). Platt Test at 8 ("I conservatively used 10% of these costs, which is 1 to 4 percentage points higher than that used in the above-mentioned projects and others, to develop a reasonable management cost estimate").

[145] *See* Platt Donan Rpt. at 27 (COTP at 5%, BC Hydro at 9%, MISO algorithm at 5%).

[146] *See* Platt Donan Rpt. at 27 ("SCE's estimate for contract construction management was approximately 14.5% of the total material costs, *excluding cable costs*, plus the craft labor costs for Alternative 1, and 13% for the Hybrid Alternative" (emphasis added)).

"contract construction management" or "Owners Agent" costs.[147] Mr. Platt applies WAPA's methodology divorced from any actual project experience or costs, and with no reference to any factual underpinning relevant to RTRP.

In contrast, SCE's Owner's Agent estimates are derived from SCE's actual project costs from Tehachapi Renewable Transmission Project (A.07-06-031) Chino Hills Underground Portion. SCE's actual Owners Agent costs for TRTP Chino Hills Underground was 14.0%.[148] SCE's estimates are based on best management practices in support of construction and assume binding terms and conditions, specified delivery schedules, *etc*. No less is expected in support of the construction of RTRP and there is no reason for SCE to ignore its past experience in favor of a WAPA calculation method which, per Mr. Platt's explanation, assigns a percentage at random and without any underpinning in reality.

There is simply no basis of fact on which to assume Mr. Platt's WAPA method provides a more accurate predictive model for Owners Agent costs than SCE's actual project experience.

B. <u>Franchise Agreement With The City of Jurupa Valley And The Risk Of An Unsupportive Local Government</u>

Q: ***Are you familiar with the "known risk" SCE described in <u>Attachment O</u> to its March 1, 2019 Direct Testimony as "Local government does not support infrastructure growth" and if so, can you expand on the significance of that "known risk"?***

A: Yes. As described in SCE's response to Gateway Properties Parties data request 2.4, "[t]he costs associated with this risk are a preliminary, non-appraised estimate of real property rights within the public right-of-way which may require procurement in support of RTRP's construction."[149] As SCE

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[147] *See* Platt Donan Rpt. at 26-27 ("Per the historical-based methodology adopted by WAPA, the *management costs* are equated to a percentage of the combined labor and material costs (minus major material costs such as cable)" (emphasis added)).

[148] *See* TRTP Owners Agent Actual Costs vs. Total Direct Construction Costs (14%), included here as <u>Attachment V-10</u>.

[149] *See* SCE Response to Gateway Properties Parties Data Request 2.4 (included as <u>Attachment V-11</u>).

explained in SCE's March 1, 2019 Direct Testimony, Section 4(g) of the Franchise Agreement governs the potential relocation of facilities installed within franchise, providing:

> Removal or Relocation of Facilities. As required by California Public Utilities Code Section 6297, [SCE] shall remove or relocate any facilities installed, used, and maintained under the franchise if and when made necessary by any lawful change of grade, alignment or width of any public street, way, alley or place. Such removal or relocation shall be performed by [SCE] without expense to the City [of Jurupa Valley]. In no event shall [SCE] be obligated to incur the cost of removal or relocation of any Facilities which were previously removed or relocated at the request of the City [of Jurupa Valley], if the City request for the removal or relocation is delivered on a date that is less than five (5) years from the date of the completion of a prior removal or relocation requested by the City with respect to such Facilities.[150]

It is this risk of relocation of RTRP facilities pursuant to Section 4(g) of the Franchise Agreement that the "known risk" of "Local government does not support infrastructure growth" is meant to address. Simply put, SCE desires to mitigate the potential risk of relocating underground RTRP facilities by acquiring property rights superior to those granted under the Franchise Agreement and extinguish the risk of compelled relocation under Section 4(g). SCE desires to mitigate any undue high-voltage transmission access charge rate burdens to state-wide customers resulting from the potentially compelled relocation of RTRP facilities located in franchise.

Q: ***In light of this, can you respond to Mr. Thompson's testimony and clarify whether the City of Jurupa Valley has offered to contribute anything to offset the additional estimated cost of***

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[150] *See* SCE Direct Testimony at 52:15 – 53:2.

undergrounding any portion of RTRP or mitigate any risks associated with any portion of the line that may be located in franchise within the City of Jurupa Valley?

A: Upon information and belief, the City of Jurupa Valley has made no offers of any monetary compensation, any forbearance of compensation it may be due pursuant to the Franchise Agreement, and/or any offers of real property rights, including but not limited to property rights superior to those that are granted to SCE pursuant to the Franchise Agreement, in exchange for the undergrounding of any part of RTRP within its public streets. Specifically, the City of Jurupa Valley has not offered SCE any property rights superior to those granted under the Franchise Agreement which would effectively extinguish the risk of compelled relocation under Section 4(g) of same.

C. Significant Ratepayer Impact Argument

Q: ***Have you read Chapter 4 of the Public Advocates Office's Direct Testimony, which is entitled, "The RTRP Will Have A Significant Cost Impact On California Ratepayers," sponsored by witness Steven Shoemaker (the "Shoemaker Testimony")?***

A: Yes.

Q: ***Would you please provide your response to the Shoemaker Testimony?***

A: I disagree with the *Shoemaker Testimony*'s suggestion that the costs of RTRP on ratepayers in the CAISO Balancing Authority Area disproportionately outweigh the benefits of providing Riverside with reliable secondary source of power, particularly with respect to SCE's Hybrid Route proposal.

First, my understanding is that the allocation system for costs of transmission lines is under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), and it is not subject to debate in this proceeding. As explained on the CPUC website, because transmission-level infrastructure like the proposed 220 kV RTRP is considered part of the interstate electrical grid, it is regulated by the FERC. FERC has established a cost allocation and recovery system known as the Transmission Access Charge ("TAC"), which consists of the sum of the charges associated with the construction, maintenance, and operation of the transmission grid.[151] As part of the TAC, a multitude of load serving entities' customers (*i.e.*¸ all of the customers of the utility entities participating in the TAC), pay a proportionate share of the costs of transmission infrastructure constructed within the CAISO territory, even for projects outside their respective utility's area that serve other utility customers' needs. FERC has repeatedly confirmed that this approach is equitable and appropriate. For example, when determining that the CAISO TAC was compliant with other FERC regulations not relevant here, FERC concluded:

> We find persuasive CAISO's explanation that CAISO's high voltage regional transmission facilities, which provide a backbone function supporting regional flows, providing transfers between California and other states, reducing congestion and facilitating reserve sharing, facilitating import and export of power and development of large—scale generation resources, benefit all users of the grid. We agree with CAISO that while the regional benefits from high voltage transmission facilities may inure to some areas of the regional grid more than others, the benefits will vary over time, as will the sectors of the grid that benefit. For the CAISO controlled grid, the effort to parse the benefits out further could lead to an allocation of costs that would not be roughly proportionate to benefits over the long run.[152]

In other words, under the TAC, there are numerous instances where the customers of any given utility pay for portions of transmission projects that benefit other utilities' customers. I assume this is quite often the case with Riverside's customers, who reside in a very small geographic area and account for a very small fraction of the overall electrical demand in the CAISO jurisdictional area compared to other utilities' customers, and yet a portion of their rates include costs to pay for other utilities' projects

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[151] *See* CPUC Website, Electric Transmission Rates and related FERC proceedings*,* available here: https://www.cpuc.ca.gov/General.aspx?id=5240 (last checked August 15, 2019).

[152] *See* 143 FERC ¶ 61,057 at Ordering Paragraph 298 (April 18, 2013), *available here*: https://www.caiso.com/Documents/Apr18_2013Order-Order1000Phase1ComplianceFilingER13-103-000.pdf

that do not directly benefit Riverside. In this regard, the RTRP is no different than any other utility project designed to benefit customers in a particular area.

An example of this arrangement is the Trans Bay Cable project, which I am informed and believe is the Bay Area Peninsula project referenced in the Lewis Testimony. I am informed and believe that the transmission revenue requirement (TRR) for that project has been established at $123 million, and I am further informed and believe that RPU (and SCE) customers pay for that project, too, as do all customers of all of the CAISO participant utilities, even though the project itself was designed only to benefit customers in a relatively small geographic area far from both SCE and Riverside.

Q: ***Do you agree with the Shoemaker Testimony's assertion that "based on the recent history of escalations in transmission construction costs, the actual increase in SCE's revenue requirement will likely be higher."***

A: I disagree with the *Shoemaker Testimony*'s assertion that RTRP is likely to be even more costly than currently expected. SCE seeks opportunities to reduce construction costs whenever feasible and safe to do so.

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.

VI.

<u>SCE's Rebuttal Testimony Regarding The RTRP Project's Estimated Scope And The Qualifications Of Roman Vazquez</u> [153]

Q: ***Please state your name and business address for the record.***

A: My name is Roman Vazquez, and my business address is 1 Innovation Way, Pomona, CA.

Q: ***Briefly describe your education, work history and present responsibilities at SCE.***

A: I graduated from California State University, Los Angeles with a Bachelor of Science degree in Civil Engineering in 1999. In 2004, I became a Registered Professional Civil Engineer with the State of California. I have worked for Southern California Edison (SCE) for 20 years, the majority of that time in the Engineering organization. Presently, I am a project engineer in the Major Projects Organization for SCE. In this position, I am responsible for the coordination of the technical and design scope of a given project.

Q: ***Please describe your role with respect to the RTRP.***

A: As Project Engineer, I am responsible for coordinating the technical and design scope related the new RTRP overhead and underground 230kV lines, the Wilderness Substation, as well as modifications to the existing transmission and distribution circuits, and other systems needed to operate the lines and substation.

Q: ***What is the purpose of your testimony in this proceeding?***

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Rebuttal Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to the 230kV underground lines. In support of this testimony, I reviewed portions of the *Testimony Of Marcor Platt On Behalf Of Sky Country Investment Co./East LLC* ("Platt Testimony"), *Direct Testimony of Steve*

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[153] This Section responds to Intervenor Direct Testimony and addresses Scoping Memo Issues ## 5 ("*Are the mitigation measures or project alternatives infeasible? This issue encompasses consideration of community values pursuant to Pub. Util. Code § 1002(a)(1)*") and 8 ("*What is the maximum prudent and reasonable cost of the project? (See Pub. Util. Code § 1005.5.)*").

Loriso on Behalf of the City of Jurupa Valley ("Loriso Testimony"), *Testimony of Matthew Webb on Behalf of Lesso Mall Development (Jurupa Valley) Limited* ("Webb Lesso Mall Testimony"), and *Testimony of Matthew Webb on Behalf of Sky Country Investment Co./East LLC* ("Webb Sky Country Testimony").

A. <u>Mr. Platt's Proposed Vault Size And Count Reduction Is Based On Inadequate Engineering Therefore His Estimated Cost Reductions For RTRP Are Without Merit</u>

Q: *Would you please respond to the assertions made in the Platt testimony with respect to the spacing and size of the proposed underground vaults?*

A: Yes. Purportedly "[b]ased on cable reel lengths and the span between vaults on similar 230 kV underground [investor owned utility (IOU)] projects as well as vendor recommendations," Mr. Platt theorizes that SCE can reduce "both the size of splice vaults and the quantity of splice vaults required for" the Hybrid Alternative and Alternative 1.[154] Mr. Platt proposes the following:

- Reducing the quantity of splice vaults from 28 to 24 for the Hybrid Alternative and 52 to 48 for Alternative 1;
- Reduce the number of telecom vaults by 2 for the Hybrid Alternative (14 to 12) and 2 for Alternative 1 (26 to 24); and
- Reduce the vault sizes from the SCE-proposed 10 feet x 10 feet x 50 feet (outside dimensions) to 10 feet x 10 feet x 26 feet (outside dimensions) based on the size of the vaults purportedly used on the Jefferson-Martin 220 kV and Sunrise 220kV underground projects.[155]

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[154] *See* Platt Donan Rpt. at 26 ("Based on cable reel lengths and the span between vaults on similar 230 kV underground IOU projects as well as vendor recommendations both the size of splice vaults and the quantity of splice vaults required for each route were reduced"); Platt Test at 7 ("I found the size of the vaults that SCE proposes to use - 8' x 8' x 48' (internal dimensions) - is approximately twice as large as that used in three other 230 kV lines constructed by PG&E and SDG&E. I found also that SCE's proposed spacing of the vaults, approximately 1500 feet apart, is less than the spacing of underground vaults in other 230 kV projects constructed by PG&E and SDG&E….")

[155] *See* Platt Donan Rpt. at 26 ("… the quantity of splice vaults were reduced from 52 to 44 for Alternative 1, and from 28 to 26 for the Hybrid Alternative. Given the reduction in splice vault clusters, the number of telecom vaults was also reduced proportionately. The vault sizes were reduced from 10 feet x 10 feet x 50 feet (outside

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In light of these assertions, Mr. Platt believes the cost for the Vault Count/Size (inclusive of their installation and components therein) for the Hybrid Alternative will be $[redacted], $[redacted] less than SCE's estimate of $[redacted]. Mr. Platt believes the Vault Count/Size (inclusive of their installation and components therein) for the Alternative 1 will be $[redacted], $[redacted] less than SCE's estimate of $[redacted] Excluding real properties acquisition, the discrepancies in the Vault Count/Size represent 8% and 7% of the total difference in estimated costs between Mr. Platt's estimates, and SCE's estimates for the Hybrid and Alternative 1, respectively.[156]

Unfortunately, cost savings based on the speculative engineering proposed by Mr. Platt are not likely. As a threshold matter and as discussed in Section V.A.1. above, the costs for the splice vaults and cable assumed by Mr. Platt are theoretical, based on non-binding bids, and are less likely to be accurate than SCE's estimates.[157] Also, RTRP proposes double-circuited lines, while the Jefferson-Martin and Sunrise transmission lines were both single-circuit.[158] Moreover, fundamentally Mr. Platt's proposed lengthening of the vault spacing to 1,800 feet, which he theorizes would reduce the quantity of splice vaults estimated to be necessary, is arbitrary and devoid of any reference to RTRP's scope and/or

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dimensions) to 10 feet x 10 feet x 26 feet (outside dimensions) vaults [fn. 20. This size of vaults was used on the Jefferson-Martin 220 and Sunrise 220kV underground projects] ...").

[156] *See* Platt Donan Rpt. at 26 ("Based on the prices obtained and the quantities used, the total material differential cost was approximately $30.6 million less than SCE's material costs for Alternative 1, and approximately $19.8 million less than SCE's material costs for the Hybrid Alternative. Additional material costs related to splicing were reduced to account for the fewer number of vaults and therefore cable splices").

[157] *See* Section V.A.1., *supra*; Platt Donan Rpt. at 26 ("…the price per vault reduced from $91,800 to $39,000. The costs for the splice vaults were obtained directly from price estimates provided by Southwire and Prysmian. The price of the cable was reduced as explained in Section 6.1.5.2.")

[158] *See* Platt Donan Rpt. at 4-5 ("Several 230 kV underground transmission line projects similar to the RTRP that were constructed by other California Investor-Owned Utilities (IOUs) were reviewed. One project was the Pacific Gas & Electric (PG&E) Jefferson-Martin 230 kV Transmission Line Project, which included a 12.4-mile underground, single-circuit 230 kV transmission line, completed in August 2006. Another was the San Diego Gas & Electric (SDG&E) Sunrise Powerlink Project which included a 6.2-mile underground, single-circuit transmission line, energized June 2012.")

proposed location.[159] Due to the presence of buried utilities in the roads where the underground construction is proposed, Mr. Platt cannot simply select a fixed vault spacing of 1,800 ft. and expect that every vault location will be free from buried encumbrances. SCE's preliminary layout of RTRP has attempted to avoid conflicts with existing utilities where known and to the greatest extent feasible. Notably, Mr. Platt also incorrectly suggested that SCE's vaults were uniformly spaced at 1,500 ft.[160] SCE's design for Alternative 1 proposes spacing over approximately 1,700 ft. (with some approaching 2,000 ft.) for more than one-half of the vaults proposed.[161]

Mr. Platt's proposed vault size reductions based on the cited PG&E (Jefferson-Martin) and SDG&E (Sunrise) 230kV lines ignores fundamental technical differences between those lines and RTRP.[162] Specifically, Mr. Platt ignores the fact that each of relevant lines have different size cables and splices: while the RTRP cable is 5,000 kcmil, upon information and belief the PG&E line (Jefferson-Martin) is 2,500 kcmil and the SDG&E line (Sunrise) was 4,000 kcmil.[163] SCE's experience on TRTP with similar sized cables at 500kV has demonstrated that larger vaults are warranted for cables systems of this size due to the thermomechanical expansion of the cables.[164]

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[159] *See* Platt Test at 7 ("Utilizing a more standard distance of 1800 feet apart reduces the number of splice vaults necessary").

[160] *See* Platt Test at 7 ("I found also that SCE's proposed spacing of the vaults, approximately 1500 feet apart, is less than the spacing of underground vaults in other 230 kV projects constructed by PG&E and SDG&E"); SEIR at 2-3 ("Vaults would be spaced in approximately 1,500-foot increments").

[161] *See* NV5, *Underground 220-kV Double Circuit Transmission Feasibility Study, Riverside Transmission Reliability Project* (Sep't. 20, 2018), ("NV5 Feasibility Study," included here as Attachment VI-1) at 16-17 (describing Alternative 1's alignment).

[162] *See* Platt Test at 4-5 (citing Jefferson-Martin, Sunrise, and the South Orange County Reliability Project); Donan Rpt. at 26, fn.20 (asserting that the quoted size of vaults was used on the Jefferson-Martin 220 and Sunrise 220kV underground projects.).

[163] *See* Platt Test. at 3 (describing the Jefferson-Martin and Sunrise projects); Platt Donan Rpt. at 4-5 (*ibid*); Pacific Gas & Electric Company, *PG&E Jefferson-Martin 230 kV Transmission Project*, WETS '07 Workshop (June 28, 2007) (1,267mm2 Copper segmental roughly converts to 2,500 kcmil), included here as Attachment VI-2.

[164] *See* Vazquez, Chy, Rector & Grant, T&D World, *Engineering a 500-kV Underground System* (Apr. 28, 2017), included here as Attachment VI-3, at 6 of 15 (discussing thermal-mechanical forces on system); *see also* Platt Donan Rpt. at 4, fn.4 (discussing TRTP undergrounding in Chino Hills).

Since the vault size and count reduction is based on inadequate engineering, Mr. Platt's estimated cost reductions for RTRP are without merit.

B. <u>SCE's Hard Digging Risk Costs Are More Likely To Be Accurate Than Mr. Platt's As They Are Based On Site-Specific Field Investigations</u>

Q: *Would you please respond to the assertions made in the Platt testimony with respect to the estimated "known risk" costs associated with "hard digging."*

A: Yes. Mr. Platt believes the hard digging risk for the Hybrid Alternative will be $[redacted] $[redacted] less than SCE's $[redacted] estimate.[165] Mr. Platt believes the hard digging risk for the Alternative One will be $[redacted] $[redacted] less than SCE's $[redacted] estimate.[166] Excluding real properties acquisition, the hard digging risk represent 15% and 19% of the total difference in estimated costs between Mr. Platt's estimates and SCE's estimates for the Hybrid and Alternative 1, respectively.

Mr. Platt misunderstand and thus mischaracterize the scope of this risk, which results in a discrepancy with SCE's estimates. The basis for Mr. Platt's estimate is a U.S. Department of Agriculture Report describing the regional geology to a maximum depth of 6 feet as "soft" sand.[167] Mr. Platt then appear to base the risk cost on an apparently randomized percentage of the SCE-determined cost to dig the right-of-way in normal soil conditions.[168]

In contrast, and as specified in the September 18, 2018 *Underground 220-kV Double Circuit Transmission Feasibility Study, Riverside Transmission Reliability Project* report by NV5 characterizing subsurface conditions in the vicinity of the proposed Project route, the underground construction

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[165] *See* Table 5-1, *supra*.

[166] *See* Table 5-1, *supra*.

[167] *See* Platt Donan Rpt. at 20 ("Furthermore, as explained above, all the soil along the proposed alignments is categorized as silty sand, which is relatively soft.").

[168] *See* Platt Donan Rpt. at 16-21 (recommending at 21 a reduction in scope cost).

proposed for RTRP has an average depth of 10 feet.[169] The "hard digging" known risk is intended to account for the hard rock/rubble deposited along the proposed RTRP alignment.[170]

SCE estimates that as much as 37.5% of the ROW could be characterized as "hard digging."[171] Assuming an average trench depth of 10 feet, SCE then estimated the amount of hard digging that may be necessary in cubic yards (CY) (11,955 CY in the case of the Hybrid Alternative), multiplied by a unit cost ($[redacted] per cubic yard of "hard digging") provided in support of TRTP.[172] This total estimated potential "hard digging" cost was multiplied by 25% to reflect SCE's estimated likelihood that the "hard digging" cost materializes.[173]

SCE's risk assessment and valuation are based on actual RTRP project information and cost information from previous projects, while Sky Country's estimates are conjecture, ignoring certain factual information exchanged during discovery. SCE's estimated risk associated with hard digging is more likely to be accurate than Mr. Platt's estimates.

C. <u>Mr. Webb's Assumption That 150-Foot Right-Of-Way Is Required In Support Of The Riser Poles Is In Error</u>

Q: *Please respond to the Webb Sky Country Testimony's assertion that 150-foot right-of-way is required to accommodate SCE's proposed riser poles.*

A: Yes. The Webb Sky Country Testimony asserts

> By placing the two poles side-by-side with 80-feet of separation, the span of the arms was scaled at a 144-feet, and we concluded that the right-of-

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[169] *See* NV5, *Underground 220-kV Double Circuit Transmission Feasibility Study, Riverside Transmission Reliability Project* (Sep't. 20, 2018), ("NV5 Feasibility Study," included here as <u>Attachment VI-1)</u> at 13 (looking at depth range of 10' to 18'), Fig. 1 (modeling for 10' depth and 7' separation).

[170] *See* NV5 Feasibility Study (Attch. VI-1) at 15 (hard digging cited as a constructability and schedule risk).

[171] *See* SCE RTRP Hard Rock Trenching Risk Worksheet, included here as <u>Attachment VI-4</u>. Hard digging risk was assumed to range from 25% on the low end to 50% on the high end. SCE elected to use the middle point of 37.5%.

[172] *See* RTRP Hard Rock Trenching Risk (Attch. VI-4) ($[redacted]).

[173] *See* SCE Direct Testimony, <u>Attachment O</u> at O-272 ($[redacted] for Hybrid Alternative), O-278 ($[redacted] for Alternative 1).

> way acquisition for this portion would likely have to be at least 150-feet in width to accommodate the tower arms and swing of conductors that might be caused by wind.[174]

While the side by side spacing of the poles remains subject to final engineering and design, SCE does not agree with the assumption that "the span of the arms [should be] scaled at a 144-feet."[175] The riser pole cross arms will only be needed to support the underground cables, not the energized overhead conductors. The conductors are planned attach the riser poles directly. The riser poles, as Mr. Webb notes, are likely to be 80 feet apart. Given these design assumptions, the conductors are not expected to require greater than 100 feet of right-of-way.

D. Mr. Webb Over-Estimates The Amount Of Land Requiring A Permanent Easement By Mistakenly Including Ground Disturbance Areas Outside Of SCE's Proposed 100-Foot Right-Of-Way.

Q: ***Please respond to Mr. Webb's suggestions that the ground disturbance areas outside of SCE's proposed 100-foot right-of-way must be permanently acquired.***

A: The Webb Sky Country Testimony asserts

> There were also 1.6 acres of taking for the transition from underground to overhead easement area, where we estimated a 150-foot right-of-way would be necessary. This resulted in 7.8 acres of permanent easement taking. We also calculated 3.6 acres of ground disturbance area for Sky Country, and some 2.9 acres of area that would be severed by the right-of-way.[176]

Similarly, the Webb Lesso Mall Testimony asserts

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[174] *See* Webb Sky Country Testimony at 5.

[175] *See* Webb Sky Country Testimony at 5.

[176] *See* Webb Sky Country Testimony at 6.

> We estimated approximately 8.7 acres of permanent easement taking, 8.5 acres of ground disturbance area, and 0.2 acres severed by the right-of-way.[177]

Mr. Webb's severed land calculations were apparently developed from the SCE's ground disturbance area (GDA) data. The GDA captures areas *outside* of the 100 ft. wide right of way, such as potential temporary construction work spaces, in order to develop estimates of maximum environmental impact for the purposes of documentation in satisfaction of the California Environmental Quality Act ("CEQA").[178] SCE does not anticipate the permanent acquisition of property outside of its planned 100 ft. right-of-way. Mr. Webb's assumption that such areas should form part of the basis for any severed land calculations is in error.

Q: ***Please respond to any assertions made in the Loriso Testimony with respect to the compatibility of the Hybrid Alternative and/or Alternative 1 with the utilities located within Jurupa Valley streets.***

A: Mr. Loriso suggests that because SCE has proposed to underground a section of the Hybrid Alternative at the intersection of Limonite Avenue and Pats Ranch Road, this "it is reasonable to conclude that the Project also can be underground according to the Alternative l," and that "the feasibility of undergrounding north of Limonite Avenue according to Alternative 1 is further confirmed by the [Chino Basin Desalter Authority (CDA) Plans]" attached as Exhibit A to Mr. Loriso's testimony.[179]

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[177] *See* Webb Lesso Mall Testimony at 6.

[178] *See* SEIR at 4.4-8 ("The GDAD represents a physical area for the purpose of analyzing potential environmental impacts within which the specific siting of permanent features (electrical infrastructure such as TSPs and LSTs) and temporary construction work spaces can be defined and adjusted in response to engineering design refinements and changed conditions").

[179] *See* Loriso Testimony at 4 ("Indeed, SCE already has proposed and agreed to underground the RTRP at the intersection of Limonite Avenue and Pats Ranch Road. Significantly, that intersection contains two large, high pressure gas lines that are 30 inches and 36inches in diameter respectively, making the location of underground transmission facilities a technically difficult proposition. Despite this, the Project's current proposal to underground at the intersection of Limonite Avenue and Pats Ranch Road and the plans for doing so demonstrate the feasibility of undergrounding the RTRP's components even at such a technically difficult and congested

(*Continued*)

To be clear, SCE's investigations to date do not evidence that the Hybrid Alternative or any Alternative studied in the FEIR or SEIR are technically infeasible.[180] SCE cautions however that its proposed design for RTRP remains conceptual, representing overhead and underground construction preliminarily deemed appropriate for this Project based on planning level assumptions, analyses performed to date, and known conditions. The precise design and location of any of RTRP's components are subject to change following completion of final engineering, identification and/or verification of field conditions, completion of underground surveys, availability of labor, material, and equipment, compliance with applicable environmental and permitting requirements, and other factors. The presence and complexity posed by existing utilities in the streets of Jurupa Valley represents a significant potential challenge. In responding to an inquiry directly from the Inland Empire Utilities Agency (IEUA) with respect to the CDA Plans,[181] SCE emphasized this caution, noting

> at this time SCE is unable to confirm whether or not it is feasible for both SCE and the Inland Empire Utilities Agency's (IEUA) planned utilities to coexist within Wineville and/or Bellegrave Avenues in the City of Jurupa Valley. As you are aware, SCE and the City of Riverside have proposed the construction of the Riverside Transmission Reliability Project (RTRP) in Jurupa Valley. While SCE has indicated its preferred project route, various route alternatives are currently under consideration by the

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Continued from the previous page
intersection. … [If] RTRP can be put underground even at such a difficult intersection, it is reasonable to conclude that the Project also can be underground according to the Alternative l, north of Limonite Avenue along Pats Ranch Road, Bellegrave Avenue, and Wineville Avenue"), 5 (referencing the CDA Plans).

[180] In contrast with SCE's March 1, 2019 Direct Testimony supporting SCE's legal arguments that alternatives considered in the FSEIR, including Alternative 1, which was designated as the environmentally superior project alternative, are infeasible as a matter of public policy. *See* SCE Direct Testimony at 37, 51 (fn. 38).

[181] The CDA was apparently formed under a Joint Exercise of Powers Agreement (JPA) among various entities, including the IEUA. *See* IEUA Website, Chino Desalters webpage, available here: https://www.ieua.org/facilities/chino-desalters/ (last checked August 15, 2019).

> California Public Utilities Commission (CPUC). Unfortunately, SCE does not anticipate it will be able to confirm whether SCE and the IEUA's respectively proposed facilities can coexist within the same right-of-way until the CPUC has approved a specific route and SCE has completed final engineering in support of that route.[182]

It is speculative for Mr. Loriso to presume technical feasibility based on SCE's proposed Hybrid Alternative and the plans of the CDA.

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.

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[182] *See* March 15, 2019 Correspondence from Roman Vazquez of SCE to Shaun Stone of IEUA, included here as Attachment VI-5.

VII.

<u>SCE's Rebuttal Testimony Regarding The RTRP Project's Consistency With Environmental Justice Principles, And The Qualifications Of Gary Busteed</u> [183]

Q: ***Please state your name and business address for the record.***

A: My name is Gary Busteed, and my business address is 2244 Walnut Grove Avenue, Rosemead, California, 91770.

Q: ***Briefly describe your education, work history and present responsibilities at SCE.***

A: I received a Masters Degree from California State University, Northridge in Biology in 2003 and a Bachelors Degree in Wildlife and Fisheries Biology from Colorado State University in 1997. I have spent more than a decade with SCE in environmental permitting and ten years with the federal government, where I developed and managed inventory and monitoring programs to study environmental change and urban habitat fragmentation for the National Park Service.

Q: ***Please describe your role with respect to the RTRP.***

A: As Senior Environmental Project Manager, I am responsible for the licensing and environmental permitting for projects such as RTRP. In this role I am responsible for habitat assessments, protocol surveys, environmental document and report development in support of CEQA and NEPA, permitting and compliance. I manage several projects that are currently in licensing and have been in this role for 8 out of my 11 years with Southern California Edison.

Q: ***What is the purpose of your testimony in this proceeding?***

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Rebuttal Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to environmental

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[183] The *Newman Testimony* and *Thompson Testimony* argue that EJ issues relate to issue numbers 5 (feasibility of alternatives given community values), 6 (overriding considerations despite significant environmental impacts) and 7 (whether the Project serves a present or future public convenience and necessity). Although it is unclear whether EJ considerations are actually responsive to those issues, my rebuttal responds to those considerations for the same reasons.

justice ("EJ") considerations, including reasons why the Hybrid Route would impose fewer EJ impacts than other possible routes considered in the FEIR certified by Riverside and the Supplemental FEIR prepared by the CPUC.

Q: ***Have you reviewed the Direct Testimony Of Gary Thompson On Behalf Of The City Of Jurupa Valley (the "Thompson Testimony") and the Direct Testimony Of Penny Newman On Behalf Of The City Of Jurupa Valley (the "Newman Testimony")?***

A: Yes, I have.

Q: ***Would you please respond to any assertions made in those testimonies that the RTRP Hybrid Route would significantly impact disadvantaged and low-income communities?***

A: Yes. I read the *Thompson Testimony* and the *Newman Testimony* to suggest that the Hybrid Route would impose substantial EJ impacts, including disproportionate impacts on both "disadvantaged communities" and "low income communities" pursuant to Senate Bill ("SB") 535 and Assembly Bill ("AB") 1550. However, both testimonies appear to disregard a number of important facts. Environmental Justice, as it is analyzed in CalEnvironScreen 3.0, takes several factors into consideration in identifying what is a disadvantaged community, including: a) environmental pollution and other hazards (such as air pollution, diesel emissions, and water quality); b) socioeconomic factors (such as the proportion of residents in the area that are unemployed, how many residents are below the poverty level, education levels in the area, and general linguistic ability in English; and c) the proportion of the local population with health risks (including cardiovascular disease and asthma).[184]

Attachment VII-1 hereto is a map of the Hybrid Alignment that shows a "heat map" of the varying degrees of EJ considerations on local neighborhoods and census tracts, based on information

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[184] *See* Update to the California Communities Environmental Health Screening Tool, CalEnviroScreen 3.0, available at https://oehha.ca.gov/media/downloads/calenviroscreen/report/ces3report.pdf (last checked August 15, 2019), at pages 5-8. According to the State of California, Office of Environmental Health Hazard Assessment's ("OEHHA's") website, CalEnviroScreen is a screening tool used to identify those California communities by census tract that are disproportionately burdened by, and vulnerable to, multiple sources of pollution. CalEnviroScreen ranks census tracts based on potential exposures to pollutants, adverse environmental conditions, socioeconomic factors and prevalence of certain health conditions. *See*, https://oehha.ca.gov/calenviroscreen/calenviroscreen-faqs.

obtained from CalEnviroScreen 3.0.[185] In reviewing the data from that website, the factors that contribute to the designation of "disadvantaged" for tract 6,065,040,607 – which includes the Hybrid Route – appear to be primarily *environmental* factors such as exposure to ozone, particulate matter, diesel emissions, and traffic, all presumably due to the proximity to the I-15 transportation corridor and commercial and industrial land uses, including distribution warehouses, in the area. The *Newman Testimony* and *Thompson Testimony* acknowledge that this tract also has a pollution burden in the 99th percentile in the State.[186]

In contrast, in arguing that the Hybrid Route would cause disproportionate EJ impacts in Jurupa Valley, the *Newman Testimony* and the *Thompson Testimony* repeatedly focus on the fact that there are low-income, minority, and/or unemployed residents in the area.[187] However, even those testimonies overlook the fact that other areas in the surrounding community appear to exhibit significantly more people in these categories than the area on or immediately adjacent to the Hybrid Route alignment. Attachment VII-2 hereto is a figure I caused to be created showing a map published by the California Air Resources Board showing designated "low-income" tracts, with the Hybrid Route also shown as an overlay.[188] As shown on that figure, the Hybrid Route is proposed for an area classified as containing far fewer "low-income" segments of the population than other nearby areas.[189] In reviewing what the *Newman Testimony* and *Thompson Testimony* refer to as "disadvantaged," tracts, it appears that tract is in approximately the 27th percentile (based on statewide distribution of values for the population that has an income lower than twice the federally recognized poverty level according to the CalEnviroScreen

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[185] The online mapping tool available at https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30 provides greater detail as to the factors that contribute to the status of each of these tracts.

[186] *See* Newman Testimony, at 5:11 and Thompson Testimony, at 9:23.

[187] *See* Newman Testimony, at 4:12 and Thompson Testimony, at 8:18.

[188] The source map that provides the starting point for this figure is available at: https://ww3.arb.ca.gov/cc/capandtrade/auctionproceeds/lowincomemapfull.htm.

[189] In fact, there are no current residential uses in the area identified as "disadvantaged" along the I-15 freeway in Jurupa Valley at all.

model), whereas in census tract 6,065,040,606 (located east of Etiwanda Avenue), the proportion of people who fall below that same poverty level is approximately in the 77th percentile.[190]

In addition, I believe the *Newman Testimony* and *Thompson Testimony* improperly disregard the impact of other developments unrelated to the proposed Hybrid Route on the tracts where the Hybrid Route would be constructed. As I understand SB 535 and as I explained earlier, a tract is deemed to be "disadvantaged" largely based on whether its inhabitants are disproportionately exposed to pollution and other hazards. I believe that the proximity to *existing* features, such as industrial and warehouse land uses and the I-15 transportation corridor, has historically contributed to why the area generally between I-15 and Wineville Avenue is a "disadvantaged community." Moreover, as shown in the 2017 Jurupa Valley General Plan, this area has been classified as an "Opportunity Zone" to encourage development of business parks, medium density housing, commercial businesses such as retail and hotels. (*See* Attachment VII-3, Figure 11-8 of the Jurupa Valley General Plan.) Several of the parties' direct testimonies suggest that industrial, retail and tourism-related projects have been contemplated in the same area where the Hybrid Route is proposed (the same areas these testimonies claim to be disadvantaged). If those projects are built and become operational, I would expect them to generate an even greater amount of vehicle trips and other activities that result in increased air quality and greenhouse gas ("GHG") emissions and traffic impacts in that area. In contrast, once construction is completed, the Hybrid Route would contribute less than significant impacts to air pollution and GHG emissions, traffic and a wide variety of other effects that would be far less impactful than under major commercial and industrial land uses. Therefore, I believe that the environmental and health factors that contribute to the tract traversed by the Hybrid Alignment being "disadvantaged" would not be exacerbated by the proposed construction of RTRP to anywhere near the same extent as if the potential future developments contemplated by the *Newman Testimony* and *Thompson Testimony* were to be constructed in the same area.

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[190] *See* CalEnviroscreen 3.0 for tracts 6,065,040,607 and 6,065,040,606.

Q: ***Do you believe that other routes for RTRP could result in even greater impacts to EJ communities than the Hybrid Route?***

A: Yes. Both the *Thompson Testimony* and *Newman Testimony* ignore the fact that SCE's proposed Hybrid Route would impose substantially fewer impacts to EJ communities than would other routes that could have been proposed by SCE. As explained in the original Final Environmental Impact Report ("FEIR") certified by the City of Riverside, several potential RTRP routing areas were considered and thoroughly vetted.[191] Those can generally be separated into three categories: 1) a western corridor (which includes both the route ultimately selected for RTRP as originally proposed to the CPUC with all overhead construction, and the route selected for the Hybrid Route); 2) central corridors (including routes along Bain Street and Van Buren Boulevard); and 3) an eastern corridor (which include routes along the Santa Ana River).[192] Among those potential corridors, the western corridor routes, including the route ultimately selected for RTRP, traverse areas with lower environmental sensitivities.[193]

Attached hereto as Attachment VII-4 is a figure created by SCE's mapping personnel to depict these three route corridors on the CalEnviroScreen map showing environmental sensitivities in western Riverside County. As shown on that Attachment, the western corridors (shown with green route lines) pass through areas with screening scores equal to, or lower than, the screening scores for the central and eastern corridors (higher scores indicate higher burdens). In other words, other route options for a second point of interconnection between RPU's system and SCE's system would have traversed areas that are already burdened by heightened amounts of EJ impacts, whereas the proposed RTRP route would traverse an area with fewer such burdens.

The same is true for the lower voltage (*i.e.*, 66 kV) subtransmission line routes SCE evaluated when preparing its portion of the *Southern California Edison Company (U 338-E) And The City Of Riverside's Joint RTRP Lower Voltage And Other Design Alternatives Report* that was filed with the

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[191] *See* FEIR, at p. 6-17.

[192] *See* FEIR, at p. 6-7.)

[193] *See* https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30.

CPUC on January 12, 2018.[194] Attachment VII-5 hereto contains a series of figures created by SCE's mapping personnel that depict these three route alternatives as an overlay on a portion of the CalEnviroScreen map. As shown on those figures, these alternative routes also would generally be located in more areas with high environmental sensitivity scores than RTRP.

In addition, when evaluating potential routes for new infrastructure, SCE considers the presence of surrounding land uses, including residential communities. For RTRP, the routing of the project line near the I-15 freeway was designed to make use of existing infrastructure and undeveloped land so as to avoid locations with established residential land uses and avoid displacing existing residents.

Q: ***Please respond to the Newman and Thompson Testimonies' assertions that the Hybrid Route exacerbates EJ impacts because it includes undergrounding through a golf course, but not in some of the residential areas in the City of Jurupa Valley's disadvantaged communities.***

A. I do not agree with the *Newman Testimony* or the *Thompson Testimony*'s statements for a number of reasons. First, as reflected in prior SCE filings in this proceeding, the purpose of SCE's proposal to underground part of RTRP was to avoid existing, under construction and established residential areas along 68th Street and Pat's Ranch Road, and not simply within a golf course, despite what those testimonies imply. Whereas the Hybrid Route would achieve that objective for areas south of Limonite Avenue (where I am informed and believe that there are established residential and golf uses but also other residential projects that are actually ongoing and/or have been fully entitled), I am further informed and believe that there are no such developments, particularly any residential communities – either existing or proposed in any explicit land use entitlements – on the properties where the Hybrid Route would remain overhead (*i.e.*, from Limonite Ave. to Langdon Ave.).

Second, according to CalEnviroScreen 3.0, the poverty score for the census tract along 68th Street (where the Hybrid Route would be underground) is substantially higher than the poverty score for

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[194] In that report, SCE provided information regarding potential subtransmission line route alternatives at lower voltage levels than the 220 kV RTRP. Three general route categories – Alternative A, Alternative B and Alternative C – were analyzed.

the tract along the I-15 Freeway that both the *Newman Testimony* and *Thompson Testimony* suggest as areas where RTRP should be undergrounded. For example, the poverty index is in the 75.31 percentile in the census tract along 68th Street, whereas it is in the 27.09 percentile along the I-15 freeway. Other low-income indicators, such as education, housing and unemployment, are also higher along the portions SCE has proposed to underground.[195] Additionally, along Wineville Road from Langdon Ave. to Cantu Galleano Road – which is within the SB 535 census tract – SCE agreed to re-engineer the overhead transmission line to avoid a recently developed residential community on the east side of Wineville Road, and moved the proposed route across the street to the west side of Wineville Road, adjacent to an industrial warehouse distribution center.

Q: *Please respond to the Newman Testimony's assertion that installation of the overhead line portion of the Hybrid Route would largely inhibit commercial development on the same properties.*

A. I believe that conclusion is speculative and unreliable. For instance, I am not aware of *any* concrete and explicit development proposal that has even been submitted to Jurupa Valley for those properties, so it appears that any claims regarding job creation, tax revenue or other economic-related issues, is speculative and unsubstantiated at this point in time.[196] To the contrary, SCE's policies permit a variety of land uses to occur within utility rights-of-way, and it is not uncommon for development associated with, or ancillary to, commercial (and other) land uses to utilize space within SCE utility corridors. Parking and agricultural activities, much like the ones currently operating in areas along the Hybrid Route are also often permitted in SCE rights-of-way. Attached hereto as Attachment VII-6 are photographs depicting several locations within SCE's service territory where transmission infrastructure coexists with active industrial, commercial and residential land uses within or adjacent to SCE rights-of-way. Similarly, I believe that the *Thompson Testimony*'s statement that "RTRP will eliminate much-needed employment opportunities for City residents, the vast majority of whom are low to median-

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[195] *See* CalEnvironScreen 3.0 for Tract 6,065,040,603.

[196] *See also*, Section IV, *supra.* (SCE's Rebuttal Testimony of Brad Thompson.)

income minorities and who suffer from the highest rate of unemployment in the region" is also speculative and unsubstantiated for the same reasons.[197]

Q: *Have you identified any other factors that influence your assessment regarding EJ impacts associated with RTRP?*

A: Yes. I recently reviewed publicly available data regarding residential home prices in and around the area closest to the proposed RTRP route. In many instances the homes in the immediate vicinity of the western corridor were valued *higher* than those in the vicinity of the central and eastern corridors. Attachment VII-7 hereto is a map and list showing residential property transactions in the City of Jurupa Valley with purchase prices of between $500,000 and $1 million over the past year. As shown on the map, a substantial number of transactions falling into that category appear to be clustered in the western corridor for RTRP, many of which appear to be in a parallel line in the immediate vicinity of the proposed Hybrid Route itself. In addition, several new home developments are currently in process in the immediate vicinity of the proposed Hybrid Route, and as depicted on the map, several of the homes in those developments have already been sold at high costs, notwithstanding the fact that for several years the proposed development of an electrical transmission project has been proposed for the same neighborhood. Those high home values suggest to me that the potential for development of the RTRP project is not having a substantial EJ impact, at least as far as home prices are concerned, on the western part of the City of Jurupa Valley.

The data also indicate to me that the types of developments being proposed for construction in the same area as RTRP – particularly residential land uses – are not likely to be marketed towards lower income individuals in the area. Therefore, to the extent that the *Newman Testimony* and *Thompson Testimony* imply that development of RTRP would deprive local low-income residents of housing, economic, and recreational opportunities, I would also disagree with that suggestion.

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[197] *See* Thompson Testimony, at 7:20-22.

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.