SOUTHERN CALIFORNIA
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company **Docket No. ER19-______-000**

SOUTHERN CALIFORNIA EDISON COMPANY

TRANSMISSION OWNER TARIFF
TRANSMISSION RATE FILING
(TO2019A)

VOLUME 2

PREPARED DIRECT TESTIMONY AND EXHIBITS

(EXHIBITS SCE-1 THRU SCE-28)

APRIL 2019

SOUTHERN CALIFORNIA EDISON®

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Prepared Direct Testimony and Supporting Exhibits (SCE-1 thru SCE-28)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
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PREPARED DIRECT TESTIMONY OF
JEFFREY L. NELSON

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-1)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
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SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
JEFFREY L. NELSON

(EXHIBIT SCE-1)

Mr. Nelson provides an overview of SCE's filing in this docket, including: 1) background on SCE's transmission system and its Base Transmission Revenue Requirement ("Base TRR"), and to explain why SCE is filing a revised formula rate at this time, 2) an overview of the design and operation of SCE's Formula Rate proposal, 3) an introduction to some of the revisions to the proposed Formula Rate that SCE compared to the currently-effective Formula Rate ("Second Formula Rate"), 4) SCE's requested implementation date for the Formula Rate, 5) an overview of SCE's requested Return on Equity ("ROE"), 6) a description of SCE's proposed Base TRR amount for June 12, 2019 based on the proposed Formula Rate, and 7) an introduction of SCE's witnesses and the purpose of their testimony.

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PREPARED DIRECT TESTIMONY OF
JEFFREY L. NELSON
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Jeffrey L. Nelson, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Please briefly describe your present responsibilities at Southern California Edison (“SCE” or “Edison”).

A. I am the Director of FERC Rates and Market Integration at Southern California Edison Company (“SCE”). My duties include managing engagement and filings with the Federal Energy Regulatory Commission (“FERC” or “Commission”) concerning California ISO market related issues, and with the preparation of revenue requirement, rate, tariff, and contract filings. This includes annual filings in support of SCE’s current Formula Transmission Rate, as well as the development of the proposed Formula Rate contained in this filing.

Q. Please briefly describe your educational and professional background.

A. I have over 25 years of experience in the electric utility industry. I’ve held positions as an electrical engineer, analyst, energy trader, and performed regulatory strategy and engagement as both a project manager and a manager. I hold a Bachelor's degree in electrical engineering from the University of California, Los Angeles, as well as an MBA from the Anderson school at UCLA. Also, I was awarded a Charted Financial Analyst charter (CFA charter) in 2003 but am currently not in active standing.

Q. Have you submitted testimony or affidavits to the Commission previously?

A. Yes. I have submitted testimony or affidavits in Dockets PA02-2, EL03-157, EL09-62, ER13-1060 and ER18-169.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

1) Provide background on SCE's transmission system and its Base Transmission Revenue Requirement ("Base TRR"), and explain why SCE is filing proposed revisions to the Formula Rate at this time;

2) Provide an overview of the design and operation of SCE's Formula Rate;

3) Describe at a high level some of the revisions to the Formula Rate that SCE is proposing in this filing as compared to the currently-effective Formula Rate ("Second Formula Rate");

4) Discuss SCE's requested implementation date for the Formula Rate;

5) Provide an overview of SCE's requested Return on Equity ("ROE");

6) Present SCE's proposed Base TRR amount for June 12, 2019 based on the Formula Rate; and,

7) Introduce SCE's witnesses and the purpose of their testimony.

II. BACKGROUND ON SCE'S BASE TRR

Q. Please define SCE's Base TRR.

A. SCE's Base TRR represents the costs of owning and operating the transmission facilities and entitlements that SCE has placed under the California Independent System Operator's ("CAISO") Operational Control. In the case where the Commission has approved recovery of Construction Work In Progress ("CWIP") in transmission rate base for certain transmission projects that will be placed under the CAISO's Operational Control, the Base TRR also includes capital costs associated with these projects in advance of their being completed and placed under the Operational Control of the CAISO. The Base TRR excludes the Transmission Revenue Balancing Account Adjustment (TRBAA) and, for wholesale purposes, also excludes Standby Transmission Revenues.

Q. Please provide background on SCE's determination of its Base TRR.

A. SCE first established a Base TRR in April of 1998, corresponding to the date upon which the CAISO assumed Operational Control of SCE's network transmission facilities. SCE's first five rate cases, covering service from 1998 through the end of 2011, were "stated rate" rate cases in which the Base TRR and associated retail and wholesale rates were determined as stated amounts, and remained in effect until the next rate case was accepted by the Commission. During the period from March, 2008 through the end of 2011 SCE also had a separate rate mechanism to recover the TRR associated with CWIP projects (established in Docket No. ER08-375), so that during that time SCE's total Base TRR was the sum of the stated rate case Base TRR and the CWIP TRR.

In 2011 SCE filed the Original Formula Rate in Docket No. ER11-3697. Since the Original Formula Rate includes recovery of CWIP costs through a component of Rate Base, the separate CWIP rate mechanism was no longer required and was terminated. The Commission accepted the Original Formula Rate effective January 1, 2012, and set the case for settlement. SCE filed a settlement offer on August 26, 2013, which the Commission approved in a letter order issued November 5, 2013.[1]

On October 27, 2017 SCE filed its Second Formula Rate. By Order dated December 29, 2017, the Commission accepted SCE's Second Formula Rate and related 2018 TRR, suspended it for a nominal period, to be effective January 1, 2018, subject to refund, and established hearing and settlement judge procedures.[2] As of the date of this filing, parties remain in settlement proceedings.

Q. Please explain how the Base TRR has been established since the Second Formula Rate became effective.

A. SCE's Formula Rate, like most formulas, provides for Annual Updates to determine the Base TRR and associated retail and wholesale transmission rates for a period of one year. The Second Formula provided for Annual updates to be filed by each December 1, with the Base TRR to be effective for the following calendar year. SCE has filed one Annual Update, TO2019 in late November of 2018, since the filing of the Second Formula Rate went into effect.

Q. Why is SCE filing a Formula Rate at this time?

A. Since the filing of the Second Formula Rate in October of 2017, regulatory and financial conditions for SCE have changed materially. In December 2017, customers in SCE's service territory were impacted by the Thomas fire. Over

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1 *Southern California Edison Co.,* 145 FERC 61,103 (2013).

2 *Southern California Edison Co.*, 161 FERC 61,309 (2017).

280,000 acres were burned, over 1,000 structures were destroyed and over 250 structures were damaged.[3] Legal and regulatory requirements which uniquely impact California utilities, such as inverse condemnation, can result in significant liability risk. SCE's parent company, Edison International ("EIX"), stockprice dropped over 20% in the ensuing three months. In part because of the increased risk of wildfire liability, Moody's downgraded SCE one notch to A3 on September 6, 2018.

The Woolsey fire began on November 8, 2018 and had a devastating impact on SCE's service territory. It was the seventh most destructive wildfire in California history.[4] The cause of the fire is still under investigation but according to California Department of Forestry and Fire Protection ("CalFire"), it burned 96,949 acres, destroyed 1,643 structures and damaged 364 others,[5] and resulted in three civilian fatalities and three firefighter injuries.[6]

Pacific Gas & Electric, which is a California utility that operates under the same regulatory environment as SCE, was even more devastated by fires, including the catastrophic Camp fire that also started on November 8, 2018. Although the cause of the Camp fire remains under review, the related fire damage burned 153,336 acres and destroyed 13,972 residences (528 commercial and 4,293 other buildings), and resulted in three firefighters

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[3] *Thomas Fire Incident Information* (updated March 14, 2019), *available at* http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=1922

[4] CalFire, *Top 20 Most Destructive California Wildfires*, *available at* http://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Destruction.pdf.

[5] CalFire, *Woolsey Incident Damage Inspection Report* CA-VNC-91023 (Nov. 20, 2018), at p. 7.

[6] *Woolsey Fire Incident Information* (updated Jan. 4, 2019), *available at* http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=2282.

injured and 85 civilian fatalities.[7] The Camp fire is the most destructive and deadly wildfire in California's history.[8]

On January 7, 2019, S&P downgraded PG&E's credit rating to below investment grade. Then, on January 14, 2019, PG&E announced plans to file for Chapter 11 bankruptcy protection and submitted this filing on January 29, 2019.

SCE's parent company stock, Edison International (EIX), has dropped dramatically since 2017 as a result of these wildfires and the continuing wildfire risk. On January 21, 2019, S&P downgraded SCE from BBB+ to BBB. On February 18, 2019, S&P issued a report entitled "Will California Still Have an Investment-Grade Investor Owned Electric Utility?" in which they warned that further downgrades should be expected unless there is regulatory action to address wildfire risks to the utilities. On March 5, 2019 Moody's downgraded SCE two notches from A3 to Baa2. And, on March 13, Fitch downgraded SCE two notches from BBB+ to BBB-.

Thus, the situation facing SCE changed so dramatically since the time of the Second Formula Rate filing that a new filing is necessary.

Q. Why has SCE determined to continue with a formula rate?

A. SCE has utilized a formula rate since 2012. During that time SCE found that, compared to a stated rate, the formula has worked beneficially for both customers and SCE. We continue to believe a formula rate is likely to reduce litigation costs relative to annual stated rate filings, and that the Commission supports formula rates for transmission owners.

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7 *Camp Fire Incident Information* (updated Jan. 4, 2019), *available at* http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=2277.

8 CalFire, *Top 20 Most Destructive California Wildfires*, March 14, 2019, *available at* http://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Destruction.pdf.

Q. What is SCE's proposed effective date for the revisions to the Formula Rate?

A. SCE's proposed effective date for the Formula Rate is June 12, 2019, in accordance with Section 2 of the Protocols.

III. OVERVIEW OF SCE'S FORMULA RATE

Q. Please provide a description of SCE's Formula Rate.

A. SCE's Formula Rate consists of two components: 1) The Formula Rate Protocols (Attachment 1 to Appendix IX of SCE's Transmission Owner Tariff); and 2) The Formula Rate Spreadsheet (Attachment 2 to Appendix IX of SCE's Transmission Owner Tariff). The Formula Rate Protocols set forth the process-related aspects of the Formula Rate, including the timelines for submission of an Annual Update, as well as set forth some requirements that SCE must adhere to. The Formula Rate Spreadsheet sets forth the calculations that are to be followed in determining the Base TRR and associated retail and wholesale rates in each Annual Update. Mr. Hansen describes in detail the structure of the Formula Rate Protocols and Spreadsheet in his testimony, Exhibit SCE-3.

Q. What is the basic structure of the determination of the Base TRR in the Formula Rate?

A. SCE's Base TRR is defined as the sum of three components: 1) the Prior Year TRR; 2) the Incremental Forecast Period TRR; and 3) the True Up Adjustment. Under certain conditions as defined in the protocols, SCE will also include a "Cost Adjustment", which would be a fourth component. Additionally, the Formula Rate calculates a "True Up TRR" that represents SCE's actual costs of owning and operating its ISO-controlled transmission assets in the year previous to the Annual Update (the "Prior Year"). The workings of each element of the Base TRR are discussed in depth by Mr. Hansen in Exhibit SCE-3.

Q. What is the Prior Year TRR?

A. The Prior Year TRR represents SCE's costs of owning and operating its ISO-controlled transmission system, measured at the end of the Prior Year. Mr. Hansen explains in detail the determination of the Prior Year TRR in his testimony, Exhibit SCE-3.

Q. What is the Incremental Forecast Period TRR?

A. The Incremental Forecast Period TRR represents the additional TRR costs that SCE expects to incur during the Rate Year (the forthcoming year for which the Base TRR determined in an Annual Update will be in effect), incremental to the costs already reflected in the Prior Year TRR. By definition, the sum of the Prior Year TRR and the Incremental Forecast Period TRR represent the expected Base TRR costs that SCE will incur during the Rate Year. Mr. Hansen explains in detail the determination of the Incremental Forecast Period TRR in his testimony, Exhibit SCE-3.

Q. What is the True Up TRR?

A. As stated above, the True Up TRR represents SCE's actual Base TRR costs experienced in the historic Prior Year. The Rate Base component of the Base TRR is calculated on an average basis over the Prior Year (as compared to the Prior Year TRR which utilized an End-of-Year Rate Base). Mr. Hansen explains in detail the determination of the True Up TRR in his testimony, Exhibit No. SCE-3.

Q. What is the True Up Adjustment?

A. The True Up Adjustment component of the Base TRR ensures that over time SCE recovers its actual costs of owning and operating its CAISO-controlled transmission assets, as defined by the True Up TRR. The True Up Adjustment is determined by comparing SCE's actual retail transmission revenues attributable to the Formula Rate to SCE's True Up TRR. The difference between the two, whether an undercollection or an overcollection, is the basis of the True Up Adjustment component of the Base TRR. Mr. Hansen explains in detail the determination of the True Up Adjustment in his testimony, Exhibit SCE-3.

Q. Is SCE proposing any revisions to the Formula Rate as compared to the Second Formula Rate?

A. Yes. While the general structure of the Formula Rate is the same, SCE is proposing some revisions to the Formula Rate, including changes to the Formula Rate Protocols and the Formula Rate Spreadsheet.

Q. Why is SCE proposing revisions to the Formula Rate?

A. The revisions that SCE is proposing to the Formula Rate are for three general reasons:

1) To correct minor errors that have been discovered since filing the Second Formula rate;
2) To reflect current conditions with respect to certain stated values in the Formula Rate (e.g. Return on Equity); and
3) To reflect changes to address unique risks SCE faces related to wildfires.

Q. Please describe some of the significant features SCE proposes to make to the Formula Rate.

A. Some significant proposed features of the Formula Rate include:

1) A new stated value for ROE (supported by Mr. Daniel Wood in Exhibit SCE-19).
2) Changes in the treatment of Total Proprietary Capital to address unique wildfire risks (supported by Mr. Sergio Deana in Exhibit SCE-17).

3) Changes in the determination of capital structure to rely more heavily on FERC Form 1 data rather than internal records (also supported by Mr. Sergio Deana in Exhibit SCE-17).

There are additional less significant revisions that SCE is proposing to make to the Formula Rate. Exhibit SCE-5, supported by Mr. Hansen, presents a listing of all proposed revisions to the Formula Rate Spreadsheet, and the witness supporting each. Exhibit SCE-6, also supported by Mr. Hansen, presents a listing of all proposed revisions to the Formula Rate Protocols.

IV. SCE's PROPOSED RETURN ON EQUITY

Q. What is SCE's proposed Return on Equity ("ROE") for this revision to the Formula Rate?

A. SCE's proposed ROE is 17.12% (excluding incentive adders). As described by Mr. Daniel Wood in SCE-19, this 17.12% ROE reflects two components. First, given the risks SCE faces excluding those associated with wildfires, Dr. Villadsen demonstrates and recommends that SCE should receive an ROE of 11.12%.[9] Mr. Wood refers to this as the "conventional ROE." Second, given the significant risks associated with wildfires faced by SCE in combination with California's inverse condemnation doctrine, Mr. Frank Graves demonstrates and recommends that SCE's investors receive an additional 6.0% ROE.[10] The recommended ROE of 17.12% represents the combined value of the conventional ROE for a utility of above-average risk like SCE without wildfire consideration (11.12%), plus the additional return necessary to account for the wildfire risk faced by SCE (6.0%).

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9 *See* Exhibit SCE-25.

10 *See* Exhibit SCE-22.

Additionally, pursuant to Commission policy, SCE proposes a 50 basis point ROE adder to reflect SCE's participation in a Commission-approved Independent System Operator, the California Independent System Operator. The sum of SCE's proposed Base ROE, and the 50 basis point CAISO participation adder is 17.62%. This value is a stated value on Line 50 of Schedule 1 of the Formula Rate Spreadsheet, and is used to calculate SCE's overall Cost of Capital Rate which is applied to SCE's Rate Base to determine the total Cost of Capital. Dr. Villadsen fully supports SCE's inclusion of the 50 basis point ROE adder in Exhibit SCE-25.

Q. Does the requested ROE, inclusive of the CAISO incentive adder, value fall within SCE's zone of reasonableness?

A. Yes. Dr. Villadsen concludes that, because of the unique wildfire related risks faced by SCE, those wildfire related risks are not captured by the zone of reasonableness of conventional electric utilities. Instead, Dr. Villadsen utilizes a different proxy group that includes capital intensive network-based companies beyond just electric utilities. And while these companies do not have the same wildfire risk as SCE, they face other risks that make them more comparable to SCE than the conventional utility-only proxy group. Dr. Villadsen concludes SCE's upper end of that zone of reasonableness is at least 18.2% and further documents that the Commission based metrics, after excluding outliers, produce ROE values as high as 19.9% under the Two Stage DCF model, and 26.4% under the Expected Earnings model. Dr. Villadsen provides details in Exhibit SCE-25.

Q. Has SCE received Commission-approved ROE adders for specific transmission projects?

A. Yes. SCE has received Commission-approved ROE Adders for three transmission projects: 1) The Tehachapi Renewable Transmission Project

("TRTP"), in the amount of 1.25%; 2) Devers to Colorado River ("DCR") project, in the amount of 1.00%; and 3) the Rancho Vista substation project, in the amount of 0.75%. Dr. Villadsen fully supports SCE's continued recovery of these Commission-approved project-specific ROE adders in Exhibit SCE-25, and Mr. Hansen describes the calculation of the dollar amount of the project specific adders in his testimony, Exhibit SCE-3.

V. SCE'S PROPOSED JANUARY 1, 2019 BASE TRR

Q. Has SCE included a populated version of the Formula Rate Spreadsheet with this filing to determine a proposed January 1, 2019 Base TRR and associated retail and wholesale transmission rates?

A. Yes. Exhibit SCE-4, supported by Mr. Hansen, is SCE's proposed Formula Rate Spreadsheet fully populated with the required cost inputs to determine a Base TRR for 2019. SCE is proposing that the Base TRR and associated rates from the proposed Formula Rate Spreadsheet become effective June 12, 2019, concurrently with the effective date that SCE is requesting for this proposed Formula Rate.

Q. If the Commission suspends the Formula Rate for five months, what is your requested date?

A. If the Commission suspends the effective date for five months,[11] SCE requests an effective date for Formula Rate of November 12, 2019. However, in the event of a suspension, SCE requests that, while the Formula Rate will be in effect beginning November 12, 2019, that for administrative and customer clarity considerations, that the associated retail and wholesale transmission

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[11] 16 U.S.C. § 824d(d) (2018).

rates be updated on January 1, 2020[12]. January 1 aligns with SCE's normal rate update cycle and the requested delay will eliminate the need to update the rates twice within a period of less than two months. To the extent that waiver is required from the Commission's rules and regulations in order for SCE to implement a January 1, 2020 rate change date in the event that the Commission suspends SCE's filing for a period of five months, SCE respectively requests waiver of any applicable rules or regulations.

Q. What is SCE'S proposed Base TRR and associated retail and wholesale transmission rates effective January 1, 2018?

A. Under the proposed rates, SCE's proposed retail Base TRR for calendar year 2019 (effective June 12, 2019) will be $1,328,294,741 (Schedule 1, Line 86 of Exhibit SCE-4). This compares to the retail Base TRR of $1,038,486,906, filed by SCE in 2018 in its TO2019 Annual Update and currently in effect. Thus, SCE is proposing revisions to the Formula Rate that will increase SCE's retail Base TRR by 27.9% compared to the Second Formula rate. SCE's proposed retail and wholesale transmission rates, calculated pursuant to Schedules 33 and 30 of the Formula Rate Spreadsheet are presented in Exhibit SCE-4.

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[12] The Formula Rate will true-up any potential mismatch between the approved Formula Rate and the wholesale and retail rates charged to customers from November 12, 2019 through December 31, 2019 as part of the normal 2019 True-up TRR process. Thus customers will be properly charged for transmission even with the slightly delayed implementation of these rates.

VI. OVERVIEW OF SCE'S WITNESSES AND TESTIMONY

Q. Please present the witnesses that will be providing testimony to support SCE's proposed revisions to the Formula Rate, and briefly describe what aspects of the Formula Rate their testimony will support.

A. The witnesses in this filing and a brief description of the aspects of the Formula Rate they are supporting are:

1) Mr. Jeffrey L. Nelson (Exhibit SCE-1)

I am providing an overview of SCE's filing.

2) Mr. Berton J. Hansen (Exhibit SCE-3)

Mr. Hansen supports the mechanics of the Formula Rate, including the calculation of the Base TRR pursuant to the Formula Rate Spreadsheet, and the requirements set forth in the Formula Rate Protocols.

3) Mr. David Gunn (Exhibit SCE-7)

Mr. Gunn supports SCE's depreciation rates and depreciation expense, and several components of SCE's Rate Base, including ISO Plant in Service and Accumulated Depreciation.

4) Mr. Jacob Moon (Exhibit SCE-9)

Mr. Moon supports the calculation of O&M Expenses, the determination of the jurisdictional split of Transmission assets between Commission and the California Public Utilities Commission by the Plant Study, and the forecast of additions to Transmission Plant in Service and CWIP projects for use in determining the Incremental Forecast Period TRR.

5) Mr. Daniel Allstun (Exhibit SCE-10)

Mr. Allstun supports the application of certain allocation factors to O&M expense accounts in order to determine the FERC jurisdictional portion of O&M expenses.

6) Mr. Alfred Lopez (Exhibit SCE-11)

Mr. Lopez supports several tax-related components of the Base TRR, including: 1) Income Tax Expense; 2) Other Taxes; 3) Accumulated Deferred Income Taxes ("ADIT"); and 4) Some components of the calculation of the Wholesale Difference to the Base TRR.

7) Mr. Robert Mindess (Exhibit SCE-12)

Mr. Mindess supports the determination of the Administrative and General ("A&G") expense component of the Base TRR, and the Franchise Fee and Uncollectibles expense components of the Base TRR.

8) Ms. Jee Kim (Exhibit SCE-13)

Ms. Kim supports the determination of the Revenue Credit component of the Base TRR.

9) Mr. Antonio Ocegueda (Exhibit SCE-15)

Mr. Ocegueda supports the calculation of the labor and plant allocation factors, as well as certain components of Rate Base and associated expenses: Network Upgrade Credits, Abandoned Plant, Plant Held for Future Use, and Regulatory Assets and Debits.

10) Mr. Robert Thomas (Exhibit SCE-16)

Mr. Thomas supports the calculation of SCE's retail transmission rates.

11) Mr. Sergio Deana (Exhibit SCE-17)

Mr. Deana supports SCE's return and capitalization.

12) Mr. Daniel Wood (Exhibit SCE-19)

Mr. Wood supports SCE's requested ROE and incentives.

13) Dr. Brian Chen (Exhibit SCE-20)

Dr. Chen describes some the actions SCE is taking on its transmission and distribution systems to help address wildfire risks.

14) Dr. Gary Stern (Exhibit SCE-21)

Dr. Stern describes many of the unique risks, beyond wildfires, that SCE faces as a utility within California's current regulatory environment.

15) Mr. Frank Graves (Exhibits SCE-22)

Mr. Graves discusses the risks wildfires pose to SCE and quantifies the impact to ROE this creates in light of these risks.

16) Dr. Bente Villadsen (Exhibit SCE-25)

Dr. Villadsen supports the calculation of what SCE's Return on Equity should be without a consideration of wildfire risks, as well as related discussion on the application of Commission incentives.

Q. Does all of the testimony in this filing represent revisions to the Second Formula Rate?

A. No. SCE's Second Formula Rate is in settlement proceedings in Dockets ER18-169-000 and EL18-44-000. Since the ultimate impact of that process on the as-filed and currently effective Second Formula Rate is unknown, this filing addresses all aspects of SCE's Formula Rate and is not intended to be subject to any changes made to the Second Formula Rate via the settlement proceedings. As a result, the testimony frequently refers to SCE's Formula Rate as the "proposed Formula Rate" even where no revisions are being proposed in a specific section of testimony.

Q. Does this complete your testimony?

A. Yes.

DECLARATION

I, Jeffrey L. Nelson, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 9, 2019 in Rosemead, California

Jeffrey L. Nelson

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<u>EXHIBIT SCE-2</u>

EXHIBIT TO THE TESTIMONY OF
MR. JEFFREY L. NELSON

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

EXHIBIT SCE-2

Responsible Witnesses for Each Schedule of the Formula Rate Spreadsheet and the Formula Rate Protocols

Schedule	Witness(es)	Exhibit SCE-___
1-Base TRR	Hansen: Lines 1-6, 8-18, 66-89 Gunn: Cash Working Capital (Line 7) Deana: Return and Capitalization (Lines 37-56, Except Line 50) Wood: Return on Common Equity (Line 50) Lopez: Other Taxes and Income Taxes (Lines 19-36 and 57-65)	3 7 17 19 11
2-IFPTRR	Hansen	3
3-TU Adjust	Hansen	3
4-TUTRR	Hansen	3
5-ROR (1,2,3,4)	Deana	17
6-Plant in Service	Gunn	7
7-Plant Study	Moon	9
8-AccDep	Gunn	7
9-ADIT	Lopez	11
10-CWIP	Gunn	7
11-PHFU	Ocegueda	15
12-Aband Plant	Ocegueda	15
13-Work Cap	Gunn	7
14-Incentive Plant	Hansen: Summary Amounts of Incentive Plant (Lines 1-38) and Summary of Incentive Projects and Incentives Granted (Lines 183-221) Gunn: Inputs for Prior Year Net Plant In Service for each Incentive project (Lines 39-182)	3 7
15-Incentive Adders	Hansen	3
16-Plant Additions	Gunn	7
17-Depreciation	Gunn	7
18-Dep Rates	Gunn	7
19-O&M	Moon: Entire Schedule except for Lines 48-87, column 5 Allstun: Allocation factors for each O&M account (Lines 48-87, column 5 "Percent ISO" percentages)	9 10
20-A&G	Mindess	12
21-Revenue Credits	Kim	13
22-NUCs	Ocegueda	15
23-Reg Assets	Ocegueda	15

24-CWIP TRR	Hansen	3
25-Wholesale Difference	Hansen: Lines 1-31 and 36-45 Gunn: Wholesale Depreciation Difference (Line 32) Lopez: Three components of wholesale Difference: Taxes Deferred - Make Up Adjustment (Line 33) Excess Deferred Taxes (Line 34) Taxes Deferred - Acct. 282 ACRS/MACRS (Line 35)	3 7 11
26-Tax Rates	Lopez	11
27-Allocators	Ocegueda: Labor and Plant Allocation Factors (Lines 1-22) Moon: O&M Allocators (Lines 23-48)	15 9
28-FF&U	Mindess	12
29-Wholesale TRRs	Hansen	3
30-Wholesale Rates	Hansen	3
31-HVLV	Moon	9
32- Gross Load	Hansen	3
33-Retail Rates	Thomas	16
34-Unfunded Reserves	Gunn	7
Protocols	Hansen	3

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BERTON J. HANSEN

(EXHIBIT SCE-3)

Mr. Hansen provides a detailed description of SCE's Formula Rate and proposed revisions to the Formula Rate, including the Formula Rate Protocols and the Formula Rate Spreadsheet. Mr. Hansen explains several cost components that are included in the Base Transmission Revenue Requirement ("TRR"), and identifies other witnesses that are responsible for other components of the Base TRR. Mr. Hansen supports Exhibit SCE-4, the populated Formula Rate Spreadsheet that develops the proposed Base TRR and associated transmission rates proposed to become effective on June 12, 2019. Additionally, Mr. Hansen explains several revisions to the Formula Rate Spreadsheet relative to the currently-effective Second Formula Rate Spreadsheet, and supports Exhibit SCE-5 (Formula Spreadsheet Revisions), a listing of all revisions to the Formula Rate Spreadsheet relative to the Second Formula Rate. Mr. Hansen also supports the Formula Rate Protocols, which set forth the process for submitting an Annual Update each year, and other requirements that SCE must adhere to. Mr. Hansen explains several revisions to the Formula Rate Protocols relative to the Second Formula Rate Protocols, and supports Exhibit SCE-6 (Formula Protocol Revisions), a listing of all revisions to the Formula Rate Protocols relative to the Second Formula Rate.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF BERTON J. HANSEN ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Berton J. Hansen, and my business address is 8631 Rush St., Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Senior Advisor in the FERC Rates and Market Integration Division of the Regulatory Affairs Department. My primary responsibilities include developing rates for services that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science Degree in economics from the University of California at Riverside, and a Master of Arts Degree in economics from the University of California at San Diego. I have been employed at SCE since 1984 in various positions, including Regulatory Economics Analyst, Power Systems Planner, Financial Analyst, Project Manager, and Senior Advisor.

Q. Have you submitted testimony to the Commission previously?

A. Yes. I have submitted testimony in four of SCE's transmission stated rate case proceedings (Docket Nos. ER02-925, ER06-186, ER08-1343, and

ER09-1534), SCE's first and second formula rate cases (Docket Nos. ER11-3697 and ER18-169), the California Independent System Operator's ("CAISO" or "ISO") Transmission Access Charge proceeding (Docket No. ER00-2019), the CAISO's Amendment 60 proceeding (Docket Nos. ER04-835 and EL04-103), and in SCE's Existing Transmission Contract Rate Case (Docket No. ER08-1353). In addition, I have submitted testimony in several of SCE's Reliability Services ("RS") cases (Docket Nos. ER02-238, ER03-142, ER04-122, ER04-890, ER04-1176, ER04-1209, ER05-410, ER05-763, ER05-1154, ER06-259, ER07-75, ER08-82, ER09-95, ER10-105, ER11-1934, ER12-201, ER13-227, ER14-222, and ER16-174).

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the details of SCE's proposed Formula Rate, including the overall structure of the formula and the annual update process, as set forth in the proposed Formula Rate Spreadsheet and Protocols. Additionally, my testimony will support SCE's proposed Base Transmission Revenue Requirements ("Base TRR") and associated retail and wholesale transmission rates to be effective on June 12, 2019 developed utilizing the proposed Formula Rate Spreadsheet populated with inputs (Exhibit No. SCE-4).

Q. What portions of the proposed Formula Rate Spreadsheet and Formula Rate Protocols will you be sponsoring?

A. I am sponsoring Schedule 1 (Base TRR), except for the Cash Working Capital calculation on Line 7, and the Return and Capitalization, Other Taxes, and Income Taxes components on Lines 19-65, Schedule 2 (Incremental Forecast Period TRR), Schedule 3 (True Up Adjustment), Schedule 4 (True Up TRR), Lines 1-38 of Schedule 14 (Incentive Plant), Schedule 15 (Incentive Adder), Schedule 24 (CWIP TRR), Schedule 29 (Wholesale TRRs), Schedule 30 (Wholesale Rates), Schedule 32 (Gross Load), and the Formula Rate Protocols in their entirety. Additionally, I am sponsoring the wholesale aspects of Cost of Service Statements BG, BH, and BL.

II. OVERVIEW OF SCE'S FORMULA RATE

Q. Please describe the overall structure of SCE's proposed Formula Rate.

A. SCE's proposed Formula Rate determines SCE's Base TRR according to the following formula:

Base TRR = Prior Year TRR +
Incremental Forecast Period TRR +
True Up Adjustment

Additionally, as explained below, under certain circumstances as defined in SCE's Formula Rate Protocols, SCE may include a Cost Adjustment in the determination of the Base TRR.

Q. What is the Prior Year?

A. The Prior Year is the most recent calendar year at the time when an Annual Update informational filing is submitted. It is the period for which SCE will have recorded costs that will be reflected in the Base TRR for the upcoming year. In this filing, SCE utilized its most recent FERC Form 1 based on 2017 data. Accordingly, SCE's Formula Spreadsheet, which develops SCE's proposed Base TRR and associated transmission rates to be effective on June 12, 2019 (as presented in Exhibit No. SCE-4) has been populated with recorded costs from SCE's 2017 FERC Form 1 and other SCE cost data from 2017. These cost inputs are substantially the same as those used in SCE's TO2019 Annual Update, filed on November 29, 2018 in Docket No. ER18-169. Inputs that are not the same, or are new in this proposed Formula Rate, are shown in Exhibit No. SCE-5 ("Formula Spreadsheet Revisions"), Section 3.

Q. What is the Rate Year?

A. The Rate Year is the year for which the Base TRR and associated rates are being set in an Annual Update filing, which is the upcoming calendar year following an Annual Update submission. Since SCE is proposing an effective date of June 12, 2019 for this filing, and is using recorded cost inputs from 2017, the Rate Year for this filing is 2019. Assuming Commission acceptance of SCE's proposed Formula Rate, the Base TRR and associated transmission rates from Exhibit SCE-4 would be in effect upon the date accepted by the Commission, through the end of 2019. Again assuming Commission acceptance of SCE's proposed Formula Rate, SCE will file by December 1, 2019 a "TO2020" Annual Update setting the Base TRR and associated transmission rates for the 2020 Rate Year.

However, in the event that the Commission accepts SCE's proposed formula rate with a five-month suspension, so that the effective date would be around November 12, 2019, SCE is seeking Commission permission to not change retail or wholesale rates until January 1, 2020. The retail and wholesale rates for January 1, 2020 would be based on SCE's TO2020 Annual Update, to be filed by December 1, 2019 utilizing this proposed formula rate. But SCE's True Up TRR (the measure of SCE's actual costs in a year, as described below) for the period at the end of 2019 during which this proposed formula rate would be effective under this scenario would be determined based on this proposed formula rate.

Q. What is the Forecast Period?

A. The Forecast Period is the 24-month period beginning the January after the Prior Year and extending through the end of the Rate Year. It is the period of time for which forecasts of additions to Plant in Service and CWIP are made in order to develop the Incremental Forecast Period TRR (which is based on the 12-month portion of the forecast that corresponds to the Rate Year). Since SCE is proposing an effective date of June 12, 2019 for this filing, and is using recorded cost inputs from 2017, the Forecast Period for this filing is January 1, 2018 through the end of 2019. Assuming Commission acceptance of SCE's proposed Formula Rate, SCE's TO2020 Annual Update will use a Forecast Period of January 2019 through December 2020.

Q. Please provide a brief description of each of the components of the Base TRR.

A. The Base TRR is composed of the Prior Year TRR, the Incremental Forecast Period TRR and the True Up Adjustment. The Prior Year TRR represents SCE's cost of service associated with the Prior Year, reflecting End of Year ("EOY") values with respect to Rate Base. It is calculated based on cost inputs from SCE's FERC Form 1 for that Prior Year, as supplemented by documented SCE records. Since the Prior Year TRR is calculated using EOY values for Rate Base, it represents SCE's cost of service at the end of the Prior Year with respect to Rate Base. The components of the Prior Year TRR are described in detail in Section III below.

The Incremental Forecast Period TRR ("IFPTRR") represents the expected incremental amount of transmission costs that SCE will incur during the Rate Year, as compared to that amount included in the Prior Year TRR. SCE's actual transmission costs are generally expected to be higher during the Rate Year than they were during the Prior Year due to Rate Base growth. The IFPTRR is included in the determination of the Base TRR to ensure that the rates being assessed during the Rate Year reflect the costs that are forecast to be incurred during that period. The determination of the IFPTRR is described in Section IV below.

The True Up Adjustment is included in the Base TRR to ensure that over time SCE collects no more and no less than its actual costs of owning and operating its transmission system. It is calculated based on the cumulative over or undercollection of actual costs at the end of the Prior Year, less an amount reflecting any amount already being returned or collected from customers in the current year. SCE's actual costs incurred during the Prior Year are defined by the "True Up TRR." The True Up TRR is very similar to the Prior Year TRR, with the difference being that Rate Base is calculated on an average over the year basis (either an average of the Beginning of Year ("BOY") and EOY values, or a 13-month average) rather than an end-of-year basis. Generally, the major Rate Base items are calculated on 13-month average year basis, including specifically ISO Transmission Plant, ISO Accumulated Depreciation, Prepayments, Materials and Supplies, and CWIP Plant. The details of the calculation of the True Up Adjustment are presented in Section VI below, while the details of the True Up TRR are presented in Section V.

Q. Do the values of the Prior Year TRR or the IFPTRR affect the costs that SCE will ultimately recover pursuant to the proposed Formula Rate?

A. No. It is only the True Up TRR that determines the amount of costs that SCE will ultimately recover pursuant to the proposed Formula Rate. The True Up Adjustment (Schedule 3 of the Formula Spreadsheet), which is based on a comparison of actual revenues to actual costs (as determined by the True Up TRR) ensures that SCE recovers over time its actual costs of owning and operating its transmission system. If SCE is cumulatively over or under collected at the end of the Prior Year, that difference is kept track of in the True Up Adjustment mechanism, and future rates are adjusted higher or lower as appropriate in the Rate Year through the True Up Adjustment component of the Base TRR.

The purpose of the Prior Year TRR and the IFPTRR components of the Base TRR is to determine a projection of the Base TRR that SCE will experience during the Rate Year, so that SCE's transmission rates may be set at a level that approximates SCE's actual costs during the Rate Year. The relationship between these inputs can be illustrated if we assume a perfectly accurate projection. That is, if the sum of the Prior Year TRR and the IFPTRR equals the True Up TRR amount ultimately obtained during that Rate Year (and assuming that SCE's forecast sales are accurate), then SCE's retail transmission rates will generate retail transmission revenues during the Rate Year equal to SCE's True Up TRR (with the True Up Adjustment component of the Base TRR returning or collecting an amount related to any previous over or undercollections).

Q. What is the "Cost Adjustment" provision, and under what circumstances would SCE include it in the determination of the Base TRR?

A. The Cost Adjustment component of the Base TRR allows SCE to reflect in the Base TRR the effect of known and significant cost impacts, either positive or negative, that differ from those that are included in the Prior Year TRR. The circumstances under which the Cost Adjustment may be utilized are set forth in the Formula Rate Protocols, Section 1, and are summarized as follows:

1) If SCE experiences a discrete cost of service item, that is not expected to recur in the Rate Year, anytime between the beginning of the Prior Year and the September 30 preceding the Annual Update filing (*i.e.*, a 21-month window) with a magnitude of greater than 3% of SCE's Base TRR, then a Cost Adjustment shall be included in the Base TRR.

2) If the discrete cost of service item occurred during the Prior Year, then the Cost Adjustment component of the Base TRR shall be an amount with the same magnitude but of the opposite sign as the discrete cost of service item.

3) If the discrete cost of service item occurred during the first nine months of the filing year (year the before the Rate Year), then the Cost Adjustment component of the Base TRR shall be an amount with the same magnitude and sign as the discrete cost of service item.

The Cost Adjustment amount may be either a positive or negative component of the Base TRR. The purpose of including this provision is to align SCE's Base TRR and rates with SCE's actual costs over time, and help assure that SCE's True Up Adjustment amounts are minimized.

Q. Why does the sign of the Cost Adjustment differ depending on whether the discrete cost of service item was experienced in the Prior Year or the first nine months of the filing year?

A. Because the consequences of the two are different in terms of how they will affect any over or under recovery during the upcoming Rate Year, or during the current filing year (previous Annual Update Rate Year). In the case where the cost item was experienced in the Prior Year, and will not recur in the Rate Year, then if that item is allowed to contribute to the TRR during the Rate Year, there will be a built in overcollection during that year associated with that item (if the item was a positive cost). That is because when the True Up TRR is determined for the Rate Year (in the Annual Update two years later), it will not include that cost. Setting the Cost Adjustment equal to the negative of the amount of the cost item in effect cancels out that built in overcollection.

If, on the other hand, the cost item occurs in the first nine months of the filing year, then that cost was not in the Prior Year TRR in the first place. So, all else equal, there will not be a built in ovecollection during the Rate Year associated with that cost. But there will be a contribution to an undercollection during the filing year, since that amount would not have been included in the previous Annual Update setting the TRR and rates for the current year. That undercollection will materialize during the next Annual Update when actual costs and actual revenues are compared for the current year. Including Cost Adjustment component of the Base TRR (positive in the case of a positive experienced discrete cost item, and negative in the case of a negative experienced discrete cost item) allows the rates to be adjusted immediately in this Rate Year rather than waiting for the subsequent Rate Year as would otherwise occur.

Q. Why is the Prior Year TRR determined based on End-of-Year Rate Base values?

A. The Prior Year TRR is determined using EOY Rate Base values to make it more likely that the sum of the Prior Year TRR and the IFPTRR will equal the costs that SCE will actually incur during the Rate Year. Using an EOY Rate Base is a method of taking a "snapshot" of SCE's costs at the EOY value, at least with respect to return on capital costs. When the Prior Year TRR is added to the IFPTRR (which represents SCE's expected incremental costs relative to the end of the Prior Year), that sum should then serve as a reasonable forecast of the actual costs that SCE will incur during the Rate Year, as determined by the True Up TRR (described in Section V below).

Q. Is SCE proposing a termination date for the proposed Formula Rate?

A. No. SCE is not proposing a termination date, and accordingly this proposed Formula Rate could operate indefinitely assuming Commission acceptance and approval. However, SCE reserves the right, as it currently has, to file pursuant to Section 205 of the Federal Power Act to revise the method of calculating its

Base Transmission Revenue Requirement. For example, SCE could propose at any time in the future another formula rate or a stated transmission rate, in which case this proposed Formula Rate would be superseded upon Commission acceptance of the new proposed Base TRR mechanism.

Q. In the event that the proposed Formula Rate were to terminate at some future date, how does the proposed Formula Rate handle any remaining amount of uncollected or overcollected revenues?

A. In the event that the proposed Formula Rate expires at some future date, the proposed Formula Rate includes a provision to determine a Final True Up Adjustment. The amount of the Final True Up Adjustment will be determined by comparing monthly revenues received to monthly costs, and including interest to the termination date of the formula rate, to determine the final over or under collected balance through the termination date of the proposed Formula Rate. SCE will be entitled and required to include the amount of this Final True Up Adjustment (either positive or negative) in SCE's successor transmission rates. Inclusion of a Final True Up Adjustment provision in the proposed Formula Rate is necessary to ensure that SCE recovers its transmission costs over the term of the formula rate.

Q. Please describe the annual update process.

A. There are three key dates in the annual update process: 1) By each June 15, SCE will post a Draft Annual Update on its website; 2) by each December 1, SCE will file the Annual Update at the Commission with a revised Base TRR and associated transmission rates for the upcoming Rate Year; and 3) each January 1 the revised Base TRR and associated transmission rates calculated pursuant to the proposed Formula Rate will become effective. These key dates in the Annual Update process are set forth in the Formula Rate Protocols, Section 3.

The Annual Update filing made by December 1 will consist of the Formula Rate Spreadsheet populated with inputs for the Prior Year from SCE's FERC Form 1, or other documented SCE sources, as well as forecasts of additions to ISO Transmission Plant, and Construction Work In Progress ("CWIP"), during the Forecast Period.

In order to provide interested parties time to review SCE's Annual Update, SCE proposes to make available for review the Draft Annual Update by June 15 each year. The Draft Annual Update will include substantially all of the same information required to be included in the upcoming Annual Update, so that the Base TRR presented in the Draft Annual Update should be the same Base TRR that SCE ultimately files in the Annual Update filing by December 1, unless input errors are identified and corrected before the Annual Update is filed.

The purpose of the five and one-half month period following the availability of the Draft Annual Update and the filing of the Annual Update is to allow interested parties to review SCE's inputs to the Formula Rate Spreadsheet, ask questions and send SCE reasonable data requests if they are unclear about any part of the Draft Annual Update, or believe that particular inputs are incorrect, or if they disagree with a forecast that SCE has made. If interested parties do identify errors in inputs that SCE made to the proposed Formula Rate in the Draft Annual Update, or propose changes that SCE believes are correct and appropriate, SCE can make corrections and include the proposed changes in the Annual Update filing. SCE's Formula Rate Protocols describe in detail the process for review and the provisions for discovery during this period, which I cover in Section XI below.

III. THE PRIOR YEAR TRR

Q. What costs are included in the Prior Year TRR?

A. The Prior Year TRR includes the following cost components:

1) Return on Capital
2) Prior Year Incentive Adder
3) Depreciation Expense
4) Operation and Maintenance Expense
5) Administrative and General Expense
6) Income Taxes
7) Other Taxes
8) Revenue Credits
9) Regulatory Debits
10) Network Upgrade Interest Expense
11) Gains and Losses on Transmission Plant Held for Future Use - Land
12) Abandoned Plant Amortization Expense
13) Franchise Fees and Uncollectibles Expenses

I will describe each of these thirteen items in turn.

Q. Please describe the Return on Capital component of the Prior Year TRR.

A. The Return on Capital component of the Prior Year TRR represents SCE's annual capital costs, including the Cost of Long Term Debt, the Cost of Preferred Stock, and the Cost of Equity. Return on Capital is calculated in Schedule 1 of the Formula Rate Spreadsheet, Lines 37 to 56. Mr. Deana describes the details of the calculation of the Return on Capital in Exhibit No. SCE-17.

Q. Please describe the Prior Year Incentive Adder component of the Prior Year TRR.

A. The Prior Year Incentive Adder quantifies the additional amount of annual revenue that SCE should receive due to ROE incentives approved by the Commission, related to the amount of Rate Base in the Prior Year that has received these ROE incentives. The Prior Year Incentive Adder is calculated in Schedule 15 of the Formula Rate Spreadsheet. I discuss in detail how the

Prior Year Incentive Adder is calculated in Section VIII.

Q. Please describe the Depreciation Expense component of the Prior Year TRR.

A. Depreciation Expense represents the annual amortization of invested capital included in SCE's Rate Base used to determine its Base TRR. Capital invested in long-lived assets (including the cost to retire the assets) is expensed over the expected useful life of the asset through Depreciation Expense. Depreciation Expense includes components related to plant booked as Transmission, Distribution, General, and Electric Miscellaneous Intangible Plant ("Intangible Plant"). Depreciation Expense is calculated in Schedule 17 of the Formula Rate Spreadsheet. Mr. Gunn describes the details of the determination of Depreciation Expense in Exhibit No. SCE-7.

The Depreciation Expense amount in the Prior Year TRR is calculated for retail customers. An adjustment to the retail depreciation expense for Wholesale customers is determined and included as one component of the "Wholesale Difference to the Base TRR," which I explain below in Section IX.

Q. Please describe the Operation and Maintenance Expense component of the Prior Year TRR.

A. Operation and Maintenance Expense ("O&M Expense") represents the costs that SCE incurs operating and maintaining its ISO transmission facilities (whose costs are included in the Base TRR). O&M Expense is calculated in Schedule 19 of the Formula Rate Spreadsheet. Mr. Moon describes the details of the determination of O&M Expense in Exhibit No. SCE-9.

Q. Please describe the Administrative and General Expense component of the Prior Year TRR.

A. Administrative and General Expense ("A&G Expense") represents the costs of SCE's administrative and general corporate expenses, which support the operation of the entire company, that are allocated to the ISO transmission function and therefore are recovered through the Base TRR. A&G Expense is calculated on Schedule 20 of the Formula Rate Spreadsheet. Mr. Mindess describes the determination of A&G Expenses in his testimony, Exhibit No. SCE-12.

Q. Please describe the Income Taxes component of the Prior Year TRR.

A. Income Taxes represent the Federal and State income taxes associated with SCE's Return on Capital in the Prior Year TRR. Income Taxes are determined pursuant to a formula, as presented in the Formula Rate Spreadsheet, Schedule 1, Lines 57 to 65. Mr. Lopez provides a detailed description of the formulary determination of Income Taxes in Exhibit No. SCE-11.

Q. Please describe the Other Taxes component of the Prior Year TRR.

A. Other Taxes are the sum of Payroll Taxes Expense and Property Taxes, and are calculated in the Formula Rate Spreadsheet in Schedule 1, Lines 19 to 36. Payroll Taxes Expense is an allocated portion of Total Electric Payroll Taxes Expense using the Wages and Salaries Allocation Factor ("W&S AF"), in accordance with Commission policy. The proposed Formula Rate reduces Total Electric Payroll Tax Expense by SCE's capitalized overhead amount before applying the W&S AF, to reflect the fact that SCE capitalizes a portion of the Electric Payroll Tax Expenses, as stated in FERC Form 1. Property Taxes are an allocated portion of Total Property Taxes, using the Transmission Plant Allocation Factor. Mr. Lopez provides a detailed description of the determination of Other Taxes in Exhibit No. SCE-11.

Q. Please describe the Revenue Credits component of the Prior Year TRR.

A. Revenue Credits are revenues that SCE receives that are attributable to the transmission assets under the ISO's Operational Control. Revenue Credits are calculated in Schedule 21 of the Formula Rate Spreadsheet. Ms. Kim describes the details of the determination of Revenue Credits in Exhibit No. SCE-13.

Q. Please describe the Regulatory Debits component of the Prior Year TRR.

A. Regulatory Debits are an amortization of "Other Regulatory Assets/Liabilities" related to SCE's ISO transmission facilities debited to FERC Account 407.3. Regulatory Debits, as well as Other Regulatory Assets/Liabilities, are by definition set to $0 initially. In order to recover any costs pursuant to this category of costs through the Prior Year TRR, SCE is required to make a Section 205 filing to the Commission and receive Commission approval. The purpose of this cost category is to provide a mechanism for any regulatory liabilities imposed on SCE by ratemaking actions of regulatory agencies to be recovered through rates. Regulatory Debits are calculated in Schedule 23 of the Formula Rate Spreadsheet. Mr. Ocegueda describes the determination of Regulatory Debits in Exhibit No. SCE-15.

Q. Please describe the Network Upgrade Interest Expense component of the Prior Year TRR.

A. Network Upgrade Interest Expenses are related to refundable upfront payments that generators make for network upgrades. When generators make such upfront payments, SCE must return the upfront payment over five years, including interest. Network Upgrade Interest Expense is the interest expense component of the payment to the generator. Network Upgrade Interest Expense is related to one of the components of Rate Base, Network Upgrade Credits. Network Upgrade Interest Expense is calculated in Schedule 22 of the Formula Rate Spreadsheet. Mr. Ocegueda discusses Network Upgrade Interest Expense in his testimony, Exhibit No. SCE-15.

Q. Please describe the Gains and Losses on Transmission Plant Held for Future Use – Land component of the Prior Year TRR.

A. Gains and Losses on Transmission Plant Held for Future Use – Land is included as a component of the Prior Year TRR because Commission policy requires such gains or losses on the land component of Transmission Plant Held for Future Use to be flowed back to ratepayers. However, gains or losses on non-land Transmission Plant Held for Future Use are not required to be flowed back to ratepayers. The Commission stated this policy in its order on the formula rate of San Diego Gas and Electric in Docket No. ER07-284 (118 FERC ¶ 61,073 P 28 (2007)). Gains and Losses on Transmission Plant held for Future Use -- Land is calculated in Schedule 11 of the Formula Rate Spreadsheet. Mr. Ocegueda describes the determination of the Gains and Losses on Transmission Plant held for Future Use – Land in his testimony, Exhibit No. SCE-15.

Q. Please describe the Abandoned Plant Amortization Expense component of the Prior Year TRR.

A. Abandoned Plant Amortization Expense is incurred in the event that SCE receives a Commission Order approving recovery of abandoned plant costs. Costs recovered through this cost category are the annual amortization of the abandoned plant costs. Abandoned Plant costs may also be included in Rate Base through the Abandoned Plant component of Rate Base. In order for SCE to recover any Abandoned Plant Amortization Expense costs through this proposed Formula Rate, SCE must make a Section 205 filing to the Commission requesting approval, and receive approval from the Commission. Abandoned Plant Amortization Expense is calculated in Schedule 12 of the Formula Rate Spreadsheet. Mr. Ocegueda describes the determination of the Abandoned Plant component of Rate Base as well as Abandoned Plant

Amortization Expense in his testimony, Exhibit No. SCE-15.

Q. Please describe the Franchise Fees and Uncollectibles components of the Prior Year TRR.

A. Franchise Fees represent the payments that SCE makes to municipal entities for the right to locate facilities within the municipality. The proposed Formula Rate determines Franchise Fees Expense by applying the Franchise Fee Factor, as approved by the California Public Utilities Commission ("CPUC"), to the total of the above-mentioned 12 cost components. Uncollectibles Expenses represent billed revenue that SCE does not collect from its retail customers. The proposed Formula Rate determines Uncollectibles Expense by applying the Uncollectibles Expense Factor approved by the CPUC to the total of the above-mentioned 12 cost components. Franchise Fees and Uncollectibles expense are calculated on Lines 79 and 80, respectively, of Schedule 1 of the Formula Rate Spreadsheet. Mr. Mindess describes the determination of the Franchise Fees and Uncollectibles Expense amounts in his testimony, Exhibit No. SCE-12.

Q. Is SCE proposing any changes to the calculation of these thirteen cost components of the Prior Year TRR compared to the Second Formula Rate currently in effect?

A. Yes. The proposed revisions to these thirteen cost components are summarized in Exhibit No. SCE-5 ("Formula Spreadsheet Revisions"). I will note that the revisions presented in Exhibit SCE-5 are relative to the Formula Spreadsheet Tariff effective on March 1, 2019, which reflects several Section 205 tariff revisions filed by SCE during the term of the Second Formula Rate.

Q. What revisions to the Formula Rate Spreadsheet tariff did SCE make during the term of the Second Formula Rate through Section 205 tariff revision filings?

A. SCE made the following Section 205 filings during the term of the Second Formula Rate seeking to revise the Formula Rate Spreadsheet Tariff (Attachment 2 to Appendix IX of SCE's Transmission Owner Tariff) on effective dates before the date of this filing:

1) Revisions to remove the "two-step" calculation of ADIT (Docket Nos. EL18-164 / ER19-845);

2) Revisions to reflect the Tax Cuts And Jobs Act of 2017 by revising tax rates and including a newly created EDIT Regulatory Liability item in ADIT (Docket No. ER18-2440);

3) Filing to Revise Retail Rates to incorporate New Transportation Electrification Rates, reflecting the addition of three new rate schedules associated with six different Rate Groups (Docket No. ER19-374);

4) Filing to Revise Schedule 33 Rate Schedules and Rate Group names to reflect the CPUC Phase 2 Decision (Docket No. ER19-1149);

5) Filing to revise the stated value of "Authorized PBOPs Expense Amount" on Schedule 20, Note 3 (Docket No. ER19-1226).

Q. Are all of tariff revisions associated with these Section 205 filings reflected in SCE's filed tariff and populated Formula Rate Spreadsheet (Exhibit SCE-4) submitted in this filing?

A. Yes. All of the filed revisions from the Section 205 filings listed above are incorporated in SCE's Formula Rate Spreadsheet tariff and in Exhibit No. SCE-4.

Q. Do these thirteen components of costs that SCE proposes to include in the Prior Year TRR reflect costs that should be included in a transmission owner's TRR?

A. Yes. These thirteen TRR cost components are all costs that SCE incurs related to providing transmission service over SCE's transmission facilities that have been placed under the Operational Control of the ISO. Accordingly, they all should be included in the Prior Year TRR.

Q. Does the proposed Formula Rate Spreadsheet calculate a transmission revenue requirement attributable only to CWIP in Rate Base costs?

A. Yes. Schedule 24 of the proposed Formula Rate Spreadsheet calculates a CWIP TRR associated with the CWIP component of Rate Base (associated only with the projects for which SCE received a Commission Order approving CWIP in Rate Base). The CWIP TRRs are calculated for both the Prior Year TRR and the Incremental Forecast Period TRR, and are calculated on both a retail (Line 87) and a wholesale (Line 88) basis. The primary purpose of calculating the CWIP TRR is informational, so that users of the proposed Formula Rate can ascertain what portion of SCE's total Base TRR is associated with CWIP in Rate Base. However, the wholesale CWIP TRR is also used as a component of the High and Low Voltage calculation performed on Schedule 29 (Line 9, Columns 2 and 3, respectively). SCE is not proposing to revise any aspect of Schedule 24.

IV. THE INCREMENTAL FORECAST PERIOD TRR

Q. Please describe how the Incremental Forecast Period TRR ("IFPTRR") is calculated.

A. The IFPTRR is calculated in Schedule 2 of the proposed Formula Rate by applying annual fixed charge rates to forecast incremental amounts of Net Plant and CWIP (relative to the end of the Prior Year amount) expected to be in place by the end of the Forecast Period (equivalently, through the end of the Rate Year). The IFPTRR treats additions to regular (non-CWIP) plant in service additions differently than CWIP additions. This is because when a plant addition is placed in service, it begins incurring operations and maintenance costs, whereas CWIP does not.

Accordingly, the IFPTRR is calculated as the sum of two components:

1) Projected cumulative additions to plant in service, less depreciation, through the Forecast Period (determined on a 13-Month average basis over the Rate Year), multiplied by an Annual Fixed Charge Rate ("AFCR"); and
2) Cumulative CWIP additions through the Forecast Period (again on a 13-Month average basis) multiplied by the AFCR for CWIP ("AFCRCWIP").

Both the net plant in service and the CWIP additions are measured relative to the end-of-year values for the Prior Year, so that the additions included in the calculation of the IFPTRR are only incremental to amounts that were already included in the calculation of the Prior Year TRR.

The AFCR represents the annual TRR costs associated with an incremental dollar of Net Plant in service. The AFCR is calculated by dividing the Prior Year TRR, excluding 75% of O&M and A&G costs, and exclusive of CWIP-related costs, by the Net Plant used in determining the Prior Year TRR. The exclusion of 75% of O&M and A&G costs is an adjustment to reflect that newer facilities are likely to incur less than average maintenance expenses relative to other SCE plant. The AFCRCWIP represents the capital costs (including income taxes) associated with CWIP in Rate Base. The AFCRCWIP is calculated based on the Weighted Cost of Long-Term Debt, and the Weighted Cost of Common and Preferred Stock. The Weighted Cost of Common and Preferred Stock is multiplied by a tax gross up factor of (1 / (1 - Composite Tax Rate)), and added to the Weighted Cost of Long Term Debt.

Q. Is SCE proposing to make any revisions to the calculation of the Incremental Forecast Period TRR on Schedule 2 compared to the Second Formula Rate?

A. No, the Schedule 2 calculation of the Incremental Forecast Period TRR is unchanged from the Second Formula Rate.

Q. What is the amount of the Incremental Forecast Period TRR proposed for rates effective June 12, 2019?

A. The proposed amount of the Incremental Forecast Period TRR is $132,737,261. *See* Schedule 2, Line 82 of the populated Formula Rate Spreadsheet, Exhibit No. SCE-4.

V. THE TRUE UP TRR

Q. What is the True Up TRR?

A. The True Up TRR represents the actual amount of costs that SCE incurred in the Prior Year, with all Rate Base items determined on an average basis, consistent with Commission cost of service policy for the determination of actual costs in a year. The primary difference between the True Up TRR and the Prior Year TRR is that the Prior Year TRR Rate Base components are determined on an EOY basis, while the True Up TRR Rate Base components are based on average basis (generally either 13-month average or average of BOY and EOY, shown on the proposed Formula Rate Spreadsheet Schedule 4, Lines

1-17 under the "Calculation Method" column). For Accumulated Deferred Income Taxes, the average is based on a "Prorata" averaging method, as shown in detail on Schedule 9 ("ADIT"). The True Up TRR includes the same cost-of-service elements as the Prior Year TRR. Since Rate Base is calculated on an average basis over the year for the True Up TRR, rather than at the end of year as in the Prior Year TRR, the Return on Capital and Income Tax expense components of the True Up TRR will differ from the amounts in the Prior Year TRR.

An additional difference between the True Up TRR and the Prior Year TRR is that expenses related to underlying stated values (see the description of a stated value in Section XII) in the proposed Formula Rate are synchronized so that the determination of the True Up TRR will be calculated based on the amount of the stated value that was in effect during the Prior Year, in those cases where the calculation of the Prior Year TRR is based on the tariff values for the stated value in effect at the time of the Annual Update. The expense items that are subject to synchronization through adjustments to the Prior Year TRR amounts are: 1) The Cost of Capital Rate (to reflect any change in Return on Equity during the Prior Year, see Schedule 4, Line 19 and Instruction 1), and 2) the Authorized PBOPs Expense Amount (see Schedule 20, Note 3). Depreciation expense is also calculated based on stated values (set forth in Schedule 18), but since the amount of Depreciation Expense included in the Prior Year TRR already reflects Commission-approved Depreciation Rates in effect each month of the Prior Year (see Schedule 17, Lines 17a-17m), no further adjustment to the True Up TRR is required to ensure that the amount of depreciation expense reflected in the True Up TRR correctly reflects Commission-approved rates that were in effect during the Prior Year.

Q. Is SCE proposing to make any revisions to the calculation of the True Up TRR on Schedule 4 compared to the Second Formula Rate?

A. No, the calculation of the True Up TRR on Schedule 4 of the proposed Formula Rate Spreadsheet is the same as the Second Formula Rate.

Q. What is the amount of the True Up TRR for the 2017 Prior Year in the proposed Formula Rate?

A. The True Up TRR for the 2017 Prior Year calculated pursuant to this proposed Formula Rate is $937,389,972, as shown on Line 46 of Schedule 4, in SCE's Exhibit SCE-4. However, as explained in Section VI below, since the True Up TRR for the 2017 Prior Year must be calculated pursuant to the Original Formula Rate, an adjustment entry is made to the True Up Adjustment to ensure that SCE only recovers actual costs as determined under the Original Formula Rate for the 2017 year. The amount of the 2017 True Up TRR calculated pursuant to the Original Formula Rate is $1,014,525,809, as shown in SCE's TO2019 Annual Update, Schedule 3 workpapers. The One Time Adjustment to reflect the difference between the Original Formula Rate and this proposed Formula Rate True Up TRRs for 2017 is $78,692,427 (developed in the Schedule 3 Workpapers), and is entered on Schedule 3, Line 23, Column 4 of Exhibit SCE-4.

VI. THE TRUE UP ADJUSTMENT

Q. Please describe how the True Up Adjustment is determined.

A. The True Up Adjustment component of the Base TRR ensures that over time SCE collects exactly its costs of owning and operating its transmission assets under the Operational Control of the ISO, as measured by the True Up TRR. The True Up Adjustment mechanism is set forth in Schedule 3 of the proposed Formula Rate Spreadsheet. It both keeps track of the cumulative over or under collection of revenues since the inception of the proposed Formula Rate, and determines the True Up Adjustment component of the Base TRR.

Q. What is the purpose of the True Up Adjustment component of the Base TRR?

A. The purpose of the True Up Adjustment is to set SCE's Base TRR at a level that will recover through retail transmission rates an amount which will return SCE's "Cumulative Excess or Shortfall in Revenue with Interest" amount close to $0 by the end of the Rate Year. That amount will not be known until the Annual Update two years following the determination of the current Annual Update, since there is a two-year lag between the Prior Year and the Rate Year.

Q. How is the cumulative over or under collection of transmission revenues calculated in Schedule 3?

A. Schedule 3 of the Formula Spreadsheet contains a module that compares the monthly True Up TRR (Column 2, Lines 12 to 23) to the actual retail transmission revenues attributable to the proposed Formula Rate (Column 3, Lines 12 to 23) for each month of the Prior Year. Interest is applied monthly based on the interest rate specified in FERC regulations (18 C.F.R. §35.19) to determine the "Cumulative Excess or Shortfall in Revenue with Interest" at the end of the Prior Year (Line 23, Column 9). That amount represents the cumulative overcollection or undercollection that must be returned to or recovered from SCE's retail transmission customers through future retail transmission rates.

Q. How is the "Cumulative Excess or Shortfall in Revenue with Interest" from the previous Annual Update considered in the determination of the current Annual Update "Cumulative Excess or Shortfall in Revenue with Interest"?

A. The amount of the "Cumulative Excess or Shortfall in Revenue with Interest" from the previous Annual Update is required to be entered into the calculation as the beginning balance. This is accomplished by entering the "Cumulative

Excess or Shortfall in Revenue with Interest" amount from the previous Annual Update on Line 11, Column 4 of Schedule 3 for the current Annual Update. Accordingly, the "Cumulative Excess or Shortfall in Revenue with Interest" in the current Annual Update (Line 23, Column 9) will reflect the entire history of any over or under collections of actual costs through the proposed Formula Rate (including the term of the Original Formula Rate), including interest.

Q. How is the True Up Adjustment amount determined?

A. The True Up Adjustment is defined as the current "Cumulative Excess or Shortfall in Revenue with Interest" minus the previous Annual Update True Up Adjustment. Projected interest is applied to that amount at the most recent FERC Interest Rate to the middle of the Rate Year (*see* Line 29 of Schedule 3).

Q. Why does the current Annual Update True Up Adjustment include the True Up Adjustment from the previous Annual Update?

A. Based on SCE's experience with the Original Formula Rate, it was observed that the True Up Adjustment as defined and implemented in the Original Formula Rate was oscillating and not returning the "Cumulative Excess or Shortfall in Revenue with Interest" amount to close to $0 by the end of the Rate Year (the True Up Adjustment in the Original Formula Rate was essentially set equal only to the "Cumulative Excess or Shortfall in Revenue with Interest"). Specifically, the magnitude of the True Up Adjustment amounts included in the first five Annual Updates with a True Up of actual costs to actual revenues (*i.e.*, beginning with the 2012 year and through the 2016 year) were: negative $68.2 million, negative $66.9 million, $13.3 million, $94.2 million, and $59.6 million.

Upon examination of the underlying time-series math, it was determined that the root cause of this was due to the two-year lag between the Rate Year and the Prior Year. Any initial over or under collection of revenues was reflected in rates twice before the True Up Adjustment from the first year could take effect. This issue was only a ratesetting issue, and did not affect the Original Formula Rate tracking of the "Cumulative Excess or Shortfall in Revenue with Interest" amounts. However, SCE sought to identify a better definition of the True Up Adjustment amount so that the True Up Adjustments would not oscillate as much as they did under the Original Formula Rate. The solution that SCE identified, and incorporated in its filing of the Second Formula Rate, was to include a subtraction of the previous Annual Update True Up Adjustment in the current Annual Update True Up Adjustment. This revision works since it prevents double recovery of any over or under recovery amounts before the True Up Adjustment affects actual revenues.

Q. Why is projected interest applied to the middle of the Rate Year in the True Up Adjustment formula?

A. Projected interest is applied to the middle of the Rate Year to set the True Up Adjustment at a level that is most likely to result in the "Cumulative Excess or Shortfall in Revenue with Interest" to $0 at the end of the Rate Year (Schedule 3, Line 29). Again, this is only a ratesetting adjustment; it will not affect the recovery of actual costs, as reflected by the amount of SCE's "Cumulative Excess or Shortfall in Revenue with Interest" at the end of the Prior Year.

Q. Has the new True Up Adjustment mechanism reduced the oscillations of the True Up Adjustments since being implemented in the Second Formula Rate?

A. There are only two data points to examine for the True Up Adjusment values, since so far there have only been two True Up Adjustments that incorporate the new True Up Adjustment mechanism (TO2018 and TO2019). However, each of those two True Up Adjustments were lower in absolute value than they would have been had the mechanism not existed. In the TO2018 filing, the True Up Adjustment was about -$40 million, as compared to the value of +$57 million that would have been filed. In the TO2019 Annual Update, the True Up Adjustment was about -$62 million, compared to the -$98 million that would have been filed.

Q. Do you propose any changes to the True Up Adjustment, as currently in effect?

A. No. The analysis that led SCE to propose revising the True Up Adjustment in the Second Formula Rate, as summarized above, remains sound. Additionally, the two lower observed values of the True Up Adjustments that utilized the new method filed provide empirical support maintaining the True Up Adjustment mechanism as established in the Second Formula Rate.

Q. What is the purpose of a One Time Adjustment?

A. A One Time Adjustment is an adjustment to costs in an Annual Update filing that relates to a period previous to the Prior Year for that Annual Update. One Time Adjustments are required to reflect any errors that are found in the determination of a True Up TRR relating to a year previous to the current Annual Update Prior Year. *See* Section 3.d.8 of the Formula Rate Protocols for a description of the circumstances under which a One Time Adjustment is required. For example, suppose that during the development of an Annual Update during year X that is determining the True Up TRR for the Prior Year of X-1, it is determined that an error that affected the True Up TRR for year X-2 in the amount of -$100,000 had occurred. This would be reflected by including a One Time Adjustment of -$100,000 in the current Annual Update filing (plus the applicable interest).

Q. How will One Time Adjustments be quantified and reflected in an Annual update filing?

A. When an error affecting the True Up TRR for a period before the current Prior Year is identified, the True Up TRR for the period of time during which the error occurred is rerun to identify the change in the True Up TRR associated with that calendar year. Interest is then applied to January of the current Prior Year to determine the One Time Adjustment. This amount is then entered as a One Time Adjustment on Line 12 of Schedule 3 of the Annual Update Formula Rate Spreadsheet.

Q. Does the proposed Formula Rate determination of the Base TRR for June 12, 2019 include any One Time Adjustments?

A. Yes, the proposed Formula Rate determination of the Base TRR for 2019 includes a One Time Adjustment of negative $137,652 (*see* Schedule 3, Line 12, Column 4 of Exhibit No. SCE-4. Ms. Kim supports the development of this One Time Adjustment in her testimony, Exhibit No. SCE-13.

Q. If the proposed Formula Rate ceases operation, is there a provision for dealing with any final over or undercollection of SCE's True Up TRR costs?

A. Yes, the proposed Formula Rate contains a Final True Up provision that will ensure that SCE will recover the actual costs incurred over the period of time that the proposed Formula Rate is in effect, as determined by the True Up TRR. *See* Section 4 of the Formula Rate Protocols, as well as Section 5 of Schedule 3, Lines 32-35.

VII. INCORPORATION OF FINAL TRUE UP ADJUSTMENT AMOUNTS FROM THE ORIGINAL AND SECOND FORMULA RATES

Q. Was there a Final True Up Adjustment provision in SCE's Original Formula Rate?

A. Yes, pursuant to the Original Formula Rate Protocols Section 4, SCE is required to calculate a Final True Up Adjustment to recover or return in SCE's successor transmission rates any amount of the cumulative over or undercollection of the True Up TRR relating to the period of time the Original Formula Rate was in effect:

> "After expiration of the Formula Rate, SCE shall calculate a Final True Up Adjustment. The Final True Up Adjustment shall cover the period of time ending on the expiration of the Formula Rate and beginning on the day after the period covered by the most recent Annual True Up Adjustment that was included in the Base TRR. For example, if the Formula Rate terminates as scheduled on December 31, 2017, SCE will determine a Final True Up Adjustment in 2018 for calendar year 2017. Except as otherwise stated in this paragraph, the Final True Up Adjustment shall be determined using the same calculation methodology as the Annual True Up Adjustment.
>
> Interest included in the Final True Up Adjustment shall be calculated through the date of the termination of the Formula Rate (or, in the event of a partial determination of the Final True Up Adjustment, through the end of the period covered by that partial determination). The Final True Up Adjustment shall be subject to the procedures described in Section 3 of the Protocols. If the Final True Up Adjustment reflects an undercollection by SCE, then SCE shall be entitled and required to recover the amount of this Final True Up Adjustment in SCE's successor transmission rates to the Formula Rate. If the Final True Up Adjustment reflects an overcollection by SCE, then SCE shall be required to refund the amount of this Final True Up Adjustment to its customers."

Q. What was the purpose of the Original Formula Rate Final True Up Adjustment provision?

A. To ensure that SCE will recover an amount of transmission revenue equal to SCE's actual FERC jurisdictional transmission costs, as determined by the

True Up TRRs determined by the Original Formula Rate, over the term of the Original Formula Rate.

Q. For what period of time was a determination of a Final True Up Adjustment relating to SCE's Original Formula Rate required?

A. For the calendar years 2016 and 2017. The years 2015 and before were already reflected in previous Annual Updates submitted pursuant to the Original Formula Rate.

Q. Have the Final True Up Adjustments relating to the entire term of the Original Formula Rate, including the 2016 and 2017 years, been determined and reflected in SCE's True Up Adjustment?

A. Yes. The True Up TRRs for both the 2016 and 2017 years, based on the Original Formula Rate, were calculated in the TO2018 filing and the TO2019 Annual Update using the Original Formula Rate and based on recorded cost information for 2016 and 2017. The overcollection from the 2016 year was quantified and included in the TO2018 filing (see Line 23 of Schedule 3 of the TO2018 filing Exhibit SCE-4), and the overcollection relating to the 2017 year was quantified and included in the TO2019 Annual Update (see Line 23 of Schedule 3 of the TO2019 Annual Update). Accordingly, the "books are closed" on the Original Formula Rate, since all over or undercollections over the entire term of the Original Formula Rate have been carried forward to the Second Formula Rate through the "Final True Up Adjustments" described above.

Q. Does the Second Formula Rate also contain a requirement that a Final True Up Adjustment be performed for the period of time that the Second Formula Rate is in effect?

A. Yes, The Second Formula Rate Protocols also require that any cumulative over or under collection of revenues through the final effective date of the

Second Formula Rate be returned or recovered from customers. *See* Section 4 of the Protocols for the Second Formula Rate:

> "In the event that this Formula Rate terminates, SCE shall calculate a Final True Up Adjustment. The Final True Up Adjustment shall cover the period of time ending on the expiration of the Formula Rate and beginning on the day after the period covered by the most recent Annual True Up Adjustment that was included in the Base TRR. For example, if the Formula Rate terminates on December 31, 2030, SCE will determine a Final True Up Adjustment in 2031 for calendar year 2030. Except as otherwise stated in this paragraph, the Final True Up Adjustment shall be determined using the same calculation methodology as the Annual True Up Adjustment."

Q. Is the cumulative over or undercollection of actual transmission costs for the 2018 year, calculated pursuant to the Second Formula Rate, known as of the date of this filing?

A. No, the True Up TRR for the 2018 year is not known at this point of time, since cost information for 2018 is not available yet.

Q. When will the Final True Up Adjustment for the Second Formula Rate be known and incorporated in the Formula Rate?

A. The Final True Up Adjustment for the 2018 year will be quantified and reflected in SCE's TO2020 Annual Update, which will use 2018 recorded cost information. The Final True Up Adjustment for the portion of the 2019 year that the Second Formula Rate is in effect in 2019 will be quantified and reflected in SCE's TO2021 Annual Update.

Q. Do the proposed revisions to the Formula Rate Protocols specify this process of determining the Final True Up Adjustments relating to the Second Formula Rate?

A. Yes. SCE is proposing revisions to the Formula Rate Protocols, Section 6 "Transition of the Original and Second Formula Rates to Successor Formula Rates", that specify how the Final True Up Adjustment relating to the term of the Second Formula Rate is to be quantified and carried forward into SCE's successor rates (*i.e.*, this proposed Formula Rate in this case).

VIII. INCLUSION OF RETURN ON EQUITY INCENTIVES IN THE FORMULA RATE

Q. Does SCE have any Commission-approved Return on Equity incentives for specific projects that are included in Rate Base?

A. Yes, as shown on Schedule 14, SCE received project-specific Return on Equity ("ROE") adders from the Commission for three projects: 1) Tehachapi Renewable Transmission Project (125 basis point ROE adder) Line 200; 2) Devers to Colorado River (100 basis point ROE adder), Line 203; and 3) the Rancho Vista substation (75 basis point ROE adder), Line 197. *See* Southern California Edison Co., 121 FERC ¶ 61,168 (2007). Schedule 14 summarizes the amounts of Incentive Plant on Lines 1-38, based on individual project information input on Lines 39-195.

Q. How does SCE's proposed Formula Rate reflect Return on Equity project incentive adders that the Commission has approved?

A. SCE's proposed Formula Rate quantifies the impact of Commission-approved ROE incentives by calculating cost components for the Prior Year TRR and for the True Up TRR which ensure that SCE recovers these ROE adder costs. These two components are:

1) The Prior Year Incentive Adder; and
2) The True Up Incentive Adder.

These two incentive adders are calculated in Schedule 15 of the proposed Formula Rate, and shown on Lines 14 and 20, respectively.

The Prior Year Incentive Adder represents the incremental impact on SCE's Prior Year TRR as a result of the above-mentioned ROE incentive adders. Similarly, the True Up Incentive Adder represents the incremental impact on SCE's True Up TRR as a result of these ROE incentive adders.

As previously discussed, it is the True Up TRR that defines the amount of transmission costs that SCE may recover through the operation of the proposed Formula Rate. Accordingly, it is only the True Up Incentive Adder that affects the amount of transmission costs that SCE will recover since it is a component of the True Up TRR. The Prior Year incentive adder is included in the Prior Year TRR for the purpose of correctly estimating the TRR costs that SCE will ultimately incur during the Rate Year, so that the magnitude of any True Up Adjustments may be minimized.

Q. Please describe how the Prior Year Incentive Adder is calculated.

A. The Prior Year Incentive Adder is calculated through the application of an Incremental Return on Equity Factor ("IREF") to the Net Plant of projects earning incentive adders. The IREF represents the incremental amount of revenue that SCE needs to receive in order to earn an extra 1.00% ROE, expressed per million dollars of Rate Base earning that extra 1.00% ROE adder.

The IREF is calculated on Line 3 of Schedule 15 according to the following formula:

IREF = CSCP * (1 / (1 – CTR)) * 1% * $1,000,000

Where:

CSCP = Common Stock Capital Percentage

CTR = Composite Tax Rate

Q. How is this formula derived so that it represents the incremental amount of revenue that SCE needs to receive in order to earn an extra 1.00% ROE, expressed per million dollars of Rate Base earning that extra 1.00% ROE adder?

A. The formula is constructed by first determining the incremental amount of equity that SCE would have as a result of $1 million of additional Rate Base. This is equal to the CSCP times $1 million. This is then multiplied by 1%, representing the hypothetical 1% increase in ROE, so that this product then represents the amount of after-tax revenue that SCE would need to retain in order to earn an incremental 1% ROE on the $1 million of Rate Base. Finally, a gross up factor is applied, representing the additional pre-tax revenue that SCE would have to receive in order to earn the required amount of after tax revenue. This gross up factor is equal to 1 / (1 – CTR). The gross up factor can be thought of as the percentage which, when multiplied by the amount of pre-tax income that remains after income taxes are paid (the 1 – CTR factor), equals one.

Q. Please explain how the IREF is used in determining the Prior Year Incentive Adder.

A. The Prior Year Incentive Adder for each individual project receiving an ROE adder is determined as the sum of the IREF times the number of million dollars of Net Plant associated with that project, and an additional multiplicative factor representing the ROE adder that the project is earning (for example, the multiplicative factor for Rancho Vista is 0.75, since it is only earning an ROE adder of 0.75%). The final amount of the Prior Year Incentive Adder is then the sum of the contribution of each project earning an ROE adder.

Q. Could you please provide an example of the calculation of the Prior Year Incentive Adder?

A. Assume the following values for inputs to the calculation:

IREF = $8,000

TRTP Net Plant = $500,000,000

Rancho Vista Net Plant = $200,000,000

Devers - Colorado River Net Plant = $400,000,000

TRTP ROE Adder = 1.25%

Rancho Vista ROE Adder = 0.75%

Devers - Colorado River ROE Adder = 1.00%

The Prior Year Incentive Adder would then be calculated as follows:

TRTP = 500 * $8,000 * 1.25 = $5,000,000

Rancho Vista = 200 * $8,000 * 0.75 = $1,200,000

DCR = 400 * $8,000 * 1.00 = $3,200,000

The total Prior Year Incentive Adder in this example is then the sum of the contribution of the three individual projects earning an ROE adder, or $9.4 million.

Q. Please describe how the True Up Incentive Adder is calculated.

A. The True Up Incentive Adder is calculated similarly to the Prior Year Incentive Adder, but using average plant balances over the Prior Year for the projects receiving the ROE adders. This True Up Incentive Adder is then included as a component of the True Up TRR.

Q. Does SCE have any Return on Equity incentives associated with being a member of the CAISO?

A. Yes, SCE has a 50 basis point ROE adder applicable to all Rate Base. Dr. Villadsen explains the basis of that 50 basis point ROE adder in her testimony, Exhibit No. SCE-25.

Q. Is SCE proposing to make any revisions to the calculation of the Prior Year Incentive Adder or the True Up Incentive Adder on Schedule 15 compared to the Second Formula Rate?

A. No, the Schedule 15 calculations are unchanged.

Q. What are the calculated amounts of the Prior Year Incentive Adder and the True Up Incentive Adder for the proposed populated Formula Rate Spreadsheet (Exhibit SCE-4)?

A. The Prior Year Incentive Adder is $28,785,307 and the True Up Incentive Adder is $29,103,495. *See* Lines 14 and 20 of Schedule 15 of the populated Formula Rate Spreadsheet, Exhibit No. SCE-4.

IX. DETERMINATION OF SCE'S WHOLESALE BASE TRR

Q. Are there differences between SCE's Base TRR used for retail ratemaking purposes as compared to the Base TRR used for wholesale ratemaking purposes?

A. Yes, SCE's cost of service differs between retail and wholesale service. The Base TRR initially calculated in the proposed Formula Rate represents the retail cost of service, and certain adjustments must be made to properly calculate the Wholesale Base TRR. Accordingly, the proposed Formula Rate defines a "Wholesale Difference to the Base TRR" for use in determining the Wholesale Base TRR. The Wholesale Base TRR is equal to the Retail Base TRR less the Wholesale Difference to the Base TRR. The Wholesale Difference to the Base TRR is calculated in Schedule 25.

Q. What are sources of the difference between SCE's Retail Base TRR and the Wholesale Base TRR?

A. SCE's Wholesale Base TRR differs from the Retail Base TRR due mainly to differences in ratemaking between retail and wholesale prior to the formation of the ISO in 1998. There are four ratemaking differences that are now being amortized over a period of 27 years beginning in 1998, to be extinguished at the end of 2024:

1) The South Georgia Make Up Adjustment;
2) The Excess Deferred Taxes Adjustment;
3) The Deferred Taxes Account 282 Adjustment; and
4) The Accumulated Depreciation Difference.

Q. How do these four Rate Base factors affect the difference between the Wholesale and Retail Base TRR?

A. Each of these four Rate Base-related adjustments affects the difference between the Wholesale and Retail Base TRR through two paths: 1) a Rate Base effect; and 2) an Expense (or amortization) effect. The Rate Base effect is due to the remaining unamortized difference in the balance between retail and wholesale ratemaking that directly affects the Wholesale Rate Base relative to the Retail Rate Base. The Expense effect is due to the annual amortization of the balances.

Q. What is the South Georgia Make Up Adjustment?

A. Mr. Lopez discusses the South Georgia Make Up Adjustment in his testimony, Exhibit No. SCE-11. As Mr. Lopez states, the South Georgia Make Up Adjustment normalizes tax benefits previously flowed through to End Use Customers. The South Georgia Make Up Adjustment currently contributes about a $35 million reduction to the Wholesale Rate Base relative to the Retail Rate Base (Line 8, Column 1 of Schedule 25). On the expense side, there is an annual amortization of $2.5 million that must be grossed up for Income Taxes, so that it serves to reduce the Wholesale Base TRR by about $3.5 million (Line 33 of Schedule 25).

Q. What is the Excess Deferred Taxes Adjustment?

A. Mr. Lopez discusses the Excess Deferred Taxes Adjustment in his testimony, Exhibit SCE-11. It is currently a reduction in Wholesale Rate Base relative to Retail of about $625,000 (Line 9, Column 1 of Schedule 25), and accounts for an annual expense reduction of about $60,000 (Line 34 of Schedule 25).

Q. What is the Deferred Taxes – Account 282 Adjustment?

A. Mr. Lopez discusses the Deferred Taxes – Account 282 Adjustment in his testimony, Exhibit SCE-11. It is currently a reduction in Wholesale Rate Base relative to Retail of about $7.4 million (Line 10, Column 1 of Schedule 25), and accounts for an annual expense reduction of about $511,000 (Line 35 of Schedule 25).

Q. What is the Accumulated Depreciation Difference?

A. Mr. Gunn explains why the Accumulated Depreciation Difference exists and how it is determined in his testimony, Exhibit SCE-7. The Accumulated Depreciation Difference is currently about $31.6 million (Line 7, Column 1 of Schedule 25), serving to increase Wholesale Rate Base relative to Retail Rate Base. The annual expense impact is $2.2 million (Line 32 of Schedule 25), increasing the Wholesale Base TRR relative to the Retail Base TRR.

Q. Are there any expense items that should not be included in the Wholesale Base TRR that are in the Retail Base TRR?

A. Yes, there are two expense items that are included in the Retail Base TRR that should not be included in the Wholesale Base TRR: 1) Uncollectibles Expense (about 0.24%) is not applied to the Wholesale Base TRR as it is to the Retail Base TRR; and 2) EPRI and EEI dues are excluded from the Wholesale TRR.

Both of these expense items are considered in developing the Wholesale Adjustment to the Base TRR as calculated on Schedule 25 of the proposed Formula Rate Spreadsheet. An "EPRI and EEI Dues Exclusion", currently about $100,000, is calculated on Lines 25-31, and Uncollectibles Expense, currently about $3.3 million, is excluded on Lines 41-42. It is appropriate to exclude EPRI and EEI Dues from wholesale rates since wholesale customers are responsible for their own EPRI and EEI Dues. Additionally, it is appropriate to exclude Uncollectibles expenses from the Wholesale TRR since uncollectibles expense only relates to retail revenue collection.

Q. Does the proposed Formula Rate provide for the Wholesale Difference to the Base TRR to change over time as the amortization of the above four items reduces the difference in Rate Base between Wholesale and Retail?

A. Yes. As the differences in these rate base items change over time (*i.e.*, from one Prior Year to the next Prior Year) according to known amortization rates, the proposed Formula Rate will recalculate the Wholesale Difference to the Base TRR. This is accomplished in the proposed Formula Rate by recalculating the Wholesale Rate Base Difference given the amortizations of each component of the difference as a function of the value of the Prior Year. Schedule 25 shows this calculation on Lines 12-15.

Q. Is SCE proposing any changes to Schedule 25 compared to the Second Formula Rate?

A. No.

Q. What is the amount of the "Wholesale Difference to the Base TRR" for the 2016 Prior Year TRR?

A. It is negative $6,100,719, as shown on Schedule 25, Line 45. This amount carries over to the calculation of the Wholesale Base TRR on Schedule 1, Line 88.

Q. What is the purpose of Schedule 29 "Wholesale TRRs" of the Formula Rate Spreadsheet?

A. Schedule 29 calculates High and Low Voltage components of SCE's total Wholesale Base TRR from Schedule 1. SCE is required to provide the High and Low Voltage components of the Wholesale Base TRR to the CAISO for its use in calculating its Transmission Access Charges. SCE is not proposing to revise Schedule 29 in this proposed Formula Rate.

X. WHOLESALE TRANSMISSION RATES

Q. What wholesale transmission rates are currently stated in SCE's Transmission Owner Tariff and calculated in the proposed Formula Rate?

A. SCE's Transmission Owner Tariff ("TO Tariff") currently sets forth three wholesale transmission rates, as follows:

1) Low Voltage Access Charge
4) High Voltage Utility Specific Rate
5) High Voltage Existing Contracts Access Charge

These rates are set forth in Appendix II of SCE's TO Tariff, and refer to SCE's Annual Update Formula Rate Spreadsheet posted on SCE's website for the actual rate in effect at any point in time. SCE's Formula Rate Spreadsheet calculates these rates in Schedule 30. As Appendix II notes, the CAISO's High Voltage Wheeling Access Charge and Low Voltage Access Charge are calculated and assessed to CAISO Wheeling customers by the CAISO, and so are not calculated in SCE's Formula Rate.

Q. Does the calculation of the Wholesale Rates performed on Schedule 30 rely on any information besides the Wholesale TRRs from Schedule 29?

A. Yes. The calculation of the Wholesale rates performed on Schedule 30 uses "Gross Load," which is the sum of SCE's forecast MWh retail sales measured at the CAISO grid level, and SCE's forecast MWh pump load for the Rate

Year. Additionally, some rates rely on "Forecast 12-CP Retail Load." The calculation of Gross Load and Forecast 12-CP Retail Load is shown on Schedule 32, Lines 4 and 5, respectively.

Q. Is SCE proposing any revisions to the determination of Gross Load in this proposed Formula Rate?

A. Yes, SCE is proposing to include a mechanism that will ensure that SCE's Pump Load component of Gross Load will over time equal actual pump load. This is accomplished through the addition of a new Line 3 Schedule 32 "Pump Load True Up", and a new Note 4 that defines the Pump Load True Up component as "equal to actual recorded less forecast Pump Load for the Prior Year". The new component is then added to the sum of SCE retail sales and the Pump Load forecast, ensuring that over time the amount of pump load equals actual MWh of Pump Load. In this filing, the Pump Load True Up input amount is 8,618 MWh, as shown in Exhibit No. SCE-4, Schedule 32.

XI. THE FORMULA RATE PROTOCOLS

Q. What are the Formula Rate Protocols?

A. The Formula Rate Protocols describe process-related items and requirements associated with the ongoing implementation of SCE's proposed Formula Rate. The Formula Rate Protocols are Attachment 1 to Appendix IX of SCE's Transmission Owner Tariff ("TO Tariff"). The Formula Rate Protocols consist of 12 Sections, as follows:

1) Introduction
2) Term of the Formula Rate
3) Procedures for Updating the Base TRR
4) The Annual True Up Adjustment and the Final True Up Adjustment
5) The Incremental Forecast Period TRR
6) Transition of the Original Formula Rate to the Formula Rate
7) Depreciation Rates
8) Revisions to Certain Formula Rate Provisions

9) Determination of Amount of Transmission Plant-ISO and Distribution Plant-ISO
10) Determination of Amount of ISO Operations and Maintenance Expense
11) Reservation of Rights
12) Use of Information

Q. Could you please describe Section 1 of the Formula Rate Protocols (Introduction)?

A. The Introduction of the Formula Rate Protocols explains some general details regarding the Formula Rate, including: 1) that the Base TRR will be calculated pursuant to the Formula Rate Spreadsheet; 2) that SCE will update its Base TRR annually; 3) the components of the Base TRR; and 4) the calculation of the Wholesale Base TRR.

Q. Could you please describe Section 2 of the Formula Rate Protocols (Term of the Formula Rate)?

A. Section 2 of the Formula Rate Protocols describes the term of the proposed Formula Rate. SCE is proposing that the proposed Formula Rate become effective June 12, 2019, or the date that the Commission makes this proposed Formula Rate effective, without any termination date, as set forth in Section 2. Additionally, Section 2 specifies that the proposed Formula Rate will remain in effect until any successor rate mechanism is made effective by the Commission.

Q. Could you please describe Section 3 of the Formula Rate Protocols (Procedures for Updating the Base TRR)?

A. Section 3 of the Formula Rate Protocols describes the procedures for updating the proposed Formula Rate, including: 1) SCE will post a Draft Annual Update on its website by June 15 of each year; and 2) SCE will file an Annual Update of its Base TRR and associated retail and wholesale rates by December 1 of each year based on the Formula Rate Spreadsheet. Section 3 also sets forth several requirements for information to be included in Draft Annual Updates and Annual Updates, and describes the requirements during the time between the posting of the Draft Annual Update and the filing of the Annual Update, including the information request requirements.

Section 3 also describes the process that SCE must follow if it determines that a previously-filed Annual Update filing contained an error in the determination of the True Up TRR in that filing. Briefly, SCE is required to determine the impact of that error by rerunning the proposed Formula Rate Spreadsheet with the correct inputs, and comparing the obtained True Up TRR with the originally-filed True Up TRR. If the error resulted in a positive change in the True Up TRR of over $1 million, then SCE must submit an Amended Annual Update filing to the Commission showing the derivation of the change in the True Up TRR; otherwise, if it is less than $1 million, SCE is not required to submit an Amended Annual Update to the Commission. SCE must also remedy the error by including as a "One Time Adjustment" the change in the True Up TRR (including interest) in the current year Annual Update. Additionally, if the error is from a year that is from "a Prior Year not more than two years previous to the Prior Year of the current Annual Update", then SCE is required to identify such an error, including quantifying the impact of the error and including that impact as a One Time Adjustment in the current year Annual Update. SCE is not obligated to take such action if the error is from a year previous to this range (*i.e.*, a Prior Year three years or more before the current Annual Update Prior Year). This limitation on the requirement to identify and quantify errors is beneficial in reducing administrative effort by both SCE and customers, while still providing a reasonable period for both SCE and customers to discover any errors in previous Annual Updates.

Q. Are you aware of any similar limitations on the requirement to recalculate errors in any Commission-jurisdictional tariffs?

A. Yes. The CAISO has a similar limitation on requirement to recalculate settlements in its Tariff. Section 11.29.8.4.7 of the CAISO Tariff limits the obligation of the CAISO to recalculate settlements to a three-year period, except as ordered by the CAISO Governing Board or pursuant to a Commission Order.

Q. Is SCE proposing any revisions to Section 3 of the Protocols?

A. Yes, SCE is proposing a revised definition of "Material Accounting Change", as set forth in footnote 4:

> "Material Accounting Changes" shall mean any material change that affects SCE's transmission rates as follows: (i) accounting policies and practices from those in effect for the Prior Year upon which the immediately preceding Annual Update was based, including those resulting from any new or revised accounting guidance from the Financial Accounting Standards Board; or (ii) internal corporate cost allocation policies or practices in effect for the Prior Year upon which the immediately preceding Annual Update was based; or (iii) income tax elections from those in effect for the Prior Year upon which the immediately preceding Annual Update was based; or (iv) cost allocation policies between EIX, SCE, and subsidiaries of either, from those in effect for the Prior Year upon which the immediately preceding Annual Update was based. Additionally, a Material Accounting Change shall also include any: (i) initial implementation of an accounting standard; or (ii) initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction."

This revised definition will provide additional detail of the situations which should be identified as a Material Accounting Change, and disclosed during the Annual Update process pursuant to Section 3.a.10 of the Protocols.

Q. Could you please describe Section 4 of the Protocols (The Annual True Up Adjustment and the Final True Up Adjustment)?

A. Section 4 of the Protocols describes the Annual True Up Adjustment and the Final True Up Adjustment. The purpose of these adjustments is to ensure that over the life of the proposed Formula Rate, SCE will recover its actual costs of service, as defined by the True Up TRRs for each year that the proposed Formula Rate is in effect. During each Annual Update, SCE will compare on a monthly basis for the Prior Year the retail transmission revenues to the True Up TRR. The monthly differences between the two will be determined, and the cumulative difference at the end of the Prior Year, including interest, will be called the "Shortfall or Excess Revenue in the Prior Year." That amount of "Shortfall or Excess Revenue in the Prior Year" will be included as the beginning balance in the next Annual Update, ensuring that over multiple Annual Updates, the True Up Adjustment mechanism will keep track of SCE's cumulative over or undercollection in revenues. Additionally, in the event that this proposed Formula Rate does terminate at some point, Section 4 describes how a Final True Up Adjustment is to be calculated and collected or returned through SCE's successor Base TRR mechanism.

Q. Is SCE proposing any revisions to Section 4 of the Protocols?

A. Yes, SCE is proposing additional language to part e of Section 4 to clarify that the Final True Up Adjustments for 2018 and the portion of the 2019 year that the Second Formula Rate is in effect shall be based on the Second Formula Rate:

> "The True Up Adjustment included in the Base TRR effective January 1, 2020 shall include the Final True Up Adjustment for the 2018 year calculated pursuant to the Second Formula Rate. The True Up Adjustment included in the Base TRR effective January 1, 2021 shall include the Final True Up Adjustment for the portion of the 2019 year for which the Second Formula Rate was in effect, calculated pursuant to the Second Formula Rate."

Q. Could you please describe Section 5 of the Protocols (The Incremental Forecast Period TRR)?

A. Section 5 of the Protocols is a brief summary of the Incremental Forecast Period TRR.

Q. Could you please describe Section 6 of the Protocols (Transition of the Original and Second Formula Rates to Successor Formula Rate)?

A. Section 6 of the Protocols describes how the ending over or under collections of revenue from the terms of the Original and Second Formula Rates are to be reflected in the proposed Formula Rate as One Time Adjustments, ensuring that SCE's actual transmission costs (as determined by the True Up TRRs) are ultimately recovered, either through revenue during those years, or as One Time Adjustments carried forward for recovery through this proposed Formula Rate.

Q. Is SCE proposing any revisions to Section 6 of the Protocols?

A. Yes, SCE is proposing revisions to ensure that the transition from the Second Formula Rate to this Formula Rate, and any future transitions, is properly handled, including how to handle a transition where a calendar year has more than one formulas in effect, as SCE anticipates will be the case for 2019. SCE is proposing to add the following paragraph at the end of Section 6:

> "Additionally, any transition from one formula rate to its successor formula rate shall ensure that the True Up TRRs for any years for which a previous formula rate or formula rates were in effect during all or part of that year are calculated utilizing the formula rate, or formula rates, that were in effect during the year being trued up. This shall be implemented through a "One Time Adjustment" reflecting the difference between the True Up TRR calculated using the Formula Rate in effect at the time of the Annual Update, and the True Up TRR calculated pursuant to the formula rate, or formula rates, that were in effect during the year being trued up. In the event that any year being trued up has two or more formulas in effect during that year, the True Up TRR for that year shall be based on a weighted

> average of the True Up TRRs calculated pursuant to the formula rates in effect that year, with the weighting being based on the number of days during the year that each was in effect. Any Annual Update which includes a Final True Up Adjustment for a previous year shall include a workpaper with a calculation of the associated One Time Adjustments."

Q. Could you please describe Section 7 of the Protocols (Depreciation Rates)?

A. Section 7 of the Formula Rate Protocols is a brief statement that the depreciation rates used in the proposed Formula Rate are stated values in the Formula Rate Spreadsheet.

Q. Could you please describe Section 8 of the Formula Rate Protocols (Revisions to Certain Formula Rate Provisions)?

A. Section 8 describes the process for making revisions to the proposed Formula Rate, including some revisions that may be made pursuant to "single-issue" filings whereby the only issue that is to be reviewed in the proceeding is that one issue. The Protocols include descriptions of five aspects of the proposed Formula Rate for which SCE is required to propose revisions to the proposed Formula Rate, and the circumstances under which SCE must make such a single-issue filing. These five aspects with single-issue filing rights are each ministerial or implementation filings, and should not subject the proposed Formula Rate to dispute, and therefore are appropriate for single-issue treatment. The five aspects for which there are single-issue filing requirements are:

1) The requirement to make conforming revisions to references in the Formula Rate to FERC Form 1 page, line, and column locations when these locations change in FERC Form 1.

2) The requirement to make revisions to the Authorized PBOPs Expense Amount on an annual basis.

3) The requirement to make revisions to the Gross Revenue Sharing Mechanism component of the Revenue Credits calculation in the event

that the California Public Utilities Commission ("CPUC") makes revisions to that mechanism.

4) The requirement to make a revision to the Formula Rate calculation of retail transmission rates to conform to CPUC rate design in the event that the CPUC revises its retail rate design.

4) The requirement to make a revision to General, Intangible, and Distribution depreciation rates stated in the Formula Rate in the event that the CPUC revises its approved General, Intangible, and Distribution depreciation rates.

Q. Is SCE proposing any revisions to Section 8 of the Protocols)?

A. Yes, SCE is proposing to remove the initial value for the Authorized PBOPs Expense Amount. That stated value is no longer relevant in this proposed Formula Rate.

Q. Could you please describe Section 9 of the Protocols (Determination of the Amount of Transmission Plant – ISO and Distribution Plant - ISO)?

A. Section 9 describes the process by which the amount of plant under the ISO's Operational Control, and thus subject to cost recovery through this proposed Formula Rate, is determined from the total dollar amount of plant booked as Transmission or Distribution.

Q. Could you please describe Section 10 of the Protocols (Determination of the Amount of ISO Operation and Maintenance Expense)?

A. Section 10 describes the determination of the amount of total Operation and Maintenance ("O&M") Expense that relates to the facilities under the ISO's Operational Control, and thus should be recovered through the proposed Formula Rate.

Q. Could you please describe Section 11 of the Protocols (Reservation of Rights)?

A. Section 11 is a statement of specific legal rights that SCE or other parties have with respect to the proposed Formula Rate, including that: 1) nothing in the Formula Rate Protocols limits the rights of intervenors in Annual Update proceedings to seek relief under the Federal Power Act ("FPA"); 2) nothing in the Formula Rate Protocols limits SCE's rights to file pursuant to Section 205 of the FPA to revise or cancel the Formula Rate; and 3) any party filing under either Section 205 or 206 of the FPA bears the standard burdens associated with such a filing.

Q. Could you please describe Section 12 of the Formula Rate Protocols (Use of Information)?

A. Section 12 describes under what conditions information produced pursuant to the Protocols may be used in other proceedings.

Q. Has SCE proposed elimination of any Protocol Sections in the currently effective Formula Rate Protocols?

A. No.

Q. Is SCE proposing any other changes to the Formula Protocols compared to the Second Formula Rate protocols?

A. Yes. In Exhibit No. SCE-6 I have summarized all proposed changes relative to the Second Formula Rate Protocols currently in effect, as stated in Appendix IX, Attachment 1, to SCE's TO Tariff.

XII. THE FORMULA RATE SPREADSHEET

Q. What is the Formula Rate Spreadsheet?

A. The Formula Rate Spreadsheet tariff sets forth the calculations to implement the calculation of SCE's Base TRR and associated retail and wholesale rates as I have described above. Attachment 2 to Appendix IX of SCE's TO Tariff shows these calculations in tariff format. In each Annual Update, SCE will implement the tariff calculation directions through the use of an Excel file populated with cost inputs.

Q. Please describe the format of the Formula Rate Spreadsheet.

A. The Formula Rate Spreadsheet consists of thirty-four individual schedules that together calculate SCE's Base TRR and associated retail and wholesale transmission rates in an Annual Update based on cost inputs and certain stated values. The first schedule, 1-Base TRR, calculates the total retail and wholesale Base TRRs, while the remaining schedules primarily determine amounts of various costs used in the 1-Base TRR schedule. Every numeric value on a line of the Formula Rate Spreadsheet used in the calculations is either: 1) a cost input; 2) a stated value; or 3) a calculated value (final or intermediate).

Q. Please describe how an input is represented in the Formula Rate Spreadsheet.

A. An input, which is generally a cost amount, is represented by a yellow-shaded location in the spreadsheet, with an associated unambiguous description of the amount to be entered in that location. In an Annual Update, SCE will follow the descriptions for each yellow-shaded input and extract the required information from FERC Form 1 or SCE's records and populate the Formula Rate Spreadsheet. Once all of the yellow-shaded inputs are populated with the appropriate inputs, the spreadsheet will calculate the ultimate outputs (primarily the Base TRR and associated retail and wholesale transmission rates).

Q. What is a stated value in the Formula Rate Spreadsheet?

A. A stated value is an amount (either dollar costs or percentages that are used in expense calculations) that is hard-wired into the Formula Rate Spreadsheet, and accordingly is not yellow-shaded as inputs are. Since a stated value is not an input, but rather a fixed component of the Formula Rate, it is not subject to revision except pursuant to FERC approval of either a Section 205 or 206 filing. Examples of stated values are Return on Equity (Schedule 1, Line 50) depreciation rates (Schedule 18), and the Authorized PBOPs Expense Amount (Schedule 20, Note 3, Line "a").

Q. Please list each of the schedules in Attachment 1, including a description of its purpose in the proposed Formula Rate, and the witness that will be sponsoring it in this filing.

A. The schedules are listed below:

Schedule 1 (BaseTRR): This schedule calculates the values for the retail and wholesale Base TRRs, in many cases utilizing information from the remaining schedules regarding the amount of various components of the Base TRR. I am sponsoring most of Schedule 1; however, Mr. David Gunn sponsors the Cash Working Capital calculation on (Line 7) in Exhibit No. SCE-7, Mr. Alfred Lopez sponsors Other Taxes and Income Taxes (Lines 19-36 and 57-65) in Exhibit No. SCE-11, Mr. Sergio Deana sponsors Return and Capitalization (Lines 37-49 and 51-56) in Exhibit No. SCE-17, and Mr. Daniel Wood sponsors Return on Common Equity on Line 50 in Exhibit No. SCE-19.

Schedule 2 (IFPTRR): This schedule calculates the Incremental Forecast Period TRR. This Schedule is discussed in Section IV of my testimony.

Schedule 3 (TrueUpAdjust): This schedule calculates the True Up Adjustment. This Schedule is discussed in Section VI of my testimony.

Schedule 4 (TrueUpTRR): This Schedule calculates the True Up TRR. It is discussed in Section V of my testimony.

Schedule 5 (ROR): This schedule calculates the capital structure and associated capital costs. It is composed of four subpart schedules:

ROR-1 (Calculation of Components of Cost of Capital Rate); ROR-2 (Calculation of 13-Month Average Capitalization Balances); ROR-3 (Cost of Debt); and ROR-4 (Cost of Preferred Stock). This Schedule is discussed in Mr. Deana's testimony, Exhibit SCE-17.

Schedule 6 (PlantInService): This schedule calculates the amount of In-Service Plant, composed of Transmission Plant – ISO, Distribution Plant – ISO, General Plant, and Intangible Plant. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 7 (PlantStudy): This schedule summarizes the results of the Plant Study, showing the amount of Transmission Plant – ISO and Distribution Plant – ISO by account. This Schedule is discussed in Mr. Moon's testimony, Exhibit SCE-9.

Schedule 8 (AccDep): This schedule calculates Accumulated Depreciation. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 9 (ADIT): This schedule calculates Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities. This Schedule is discussed in Mr. Lopez's testimony, Exhibit SCE-11.

Schedule 10 (CWIP): This schedule presents CWIP balances in the Prior Year for each project that SCE has Commission approval to include in Rate Base, and presents forecast amounts of CWIP for each project through the end of the Forecast Period, and calculates the Incremental CWIP amounts for use in calculating the Incremental Forecast Period TRR. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 11 (PHFU): This schedule calculates Plant Held for Future Use, as well as any "Gain or Loss on Transmission Plant Held for Future Use – Land." This Schedule is discussed in Mr. Ocegueda's testimony, Exhibit SCE-15.

Schedule 12 (AbandonedPlant): This schedule calculates Abandoned Plant balances and Abandoned Plant Amortization Expense. This Schedule is discussed in Mr. Ocegueda's testimony, Exhibit SCE-15.

Schedule 13 (WorkCap): This schedule calculates the Materials and Supplies and Prepayments components of Working Capital. This Schedule is discussed Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 14 (IncentivePlant): This schedule summarizes Incentive Plant balances for each project for which SCE has Commission approval to include in Rate Base, or that earns an ROE adder (or both). This Schedule is discussed in Section VIII of my testimony (for Lines 1-38, summary of Amounts of Incentive Plant), and Mr. Gunn's testimony, Exhibit SCE-7, for the amounts of Prior Year Net Plant in Service (Lines 39-195).

Schedule 15 (IncentiveAdder): This schedule calculates the ROE Incentive Adders to include in both the Prior Year TRR and the True Up TRR. This Schedule is discussed in Section VIII of my testimony.

Schedule 16 (PlantAdditions): This schedule presents SCE's Forecast Plant Additions for in-service plant. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 17 (Depreciation): This schedule calculates Depreciation Expense. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 18 (DepRates): This schedule presents the depreciation rates that the Formula Rate Spreadsheet uses to calculate depreciation expense. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 19 (OandM): This schedule calculates Operations and Maintenance Expense. This Schedule is discussed in Mr. Moon's testimony, Exhibit SCE-9, as well as Mr. Allstun's testimony, Exhibit No. SCE-10.

Schedule 20 (AandG): This schedule calculates Administrative and General Expense. This Schedule is discussed in Mr. Mindess' testimony Exhibit SCE-12.

Schedule 21 (RevenueCredits): This schedule calculates the Revenue Credits, including credits pursuant to the CPUC-authorized Gross Revenue Sharing Mechanism ("GRSM"). This Schedule is discussed in Ms. Kim's testimony, Exhibit SCE-13.

Schedule 22 (NUCs): This schedule calculates Network Upgrade Credits and Interest on Network Upgrade Credits. This Schedule is discussed in Mr. Ocegueda's testimony, Exhibit SCE-15.

Schedule 23 (RegAssets): This schedule calculates Regulatory Assets/Liabilities and Regulatory Debits. This Schedule is discussed in Mr. Ocegueda's testimony, Exhibit SCE-15.

Schedule 24 (CWIPTRR): This schedule calculates, for informational purposes only, the contribution of CWIP in Rate Base to the Prior Year TRR, the Incremental Forecast Period TRR, the True Up TRR, and the Retail Base TRR. This Schedule is discussed in Section III of my testimony.

Schedule 25 (WholesaleDifference): This schedule calculates the Wholesale Difference to the Base TRR. This Schedule is discussed in Section IX of my testimony.

Schedule 26 (TaxRates): This schedule calculates the tax rates used in the Formula Rate Spreadsheet, including the Federal Income Tax Rate and the Composite State Income Tax Rate. This Schedule is discussed in Mr. Lopez's testimony, Exhibit SCE-11.

Schedule 27 (Allocators): This schedule calculates the Transmission Wages and Salaries Allocation factor and the Transmission Plant Allocation Factor, as well as certain allocation factors that are used in the calculation of ISO O&M

Expense. Mr. Ocegueda discusses the Transmission Wages and Salaries Allocation factor and the Transmission Plant Allocation Factor in his testimony, Exhibit No. SCE-15. Mr. Moon discusses the allocation factors used in the calculation of ISO O&M Expense in his testimony, Exhibit SCE-9.

Schedule 28 (FFU): This schedule calculates the Franchise Fee and Uncollectibles Factors used in the Formula Rate Spreadsheet to calculate Franchise Fees Expense and Uncollectibles Expense. This Schedule is discussed in Mr. Mindess' testimony, Exhibit SCE-12.

Schedule 29 (WholesaleTRRs): This schedule calculates the Wholesale TRRs used in the determination of the Wholesale Transmission Rates. This Schedule is discussed in Section IX of my testimony.

Schedule 30 (WholesaleRates): This schedule calculates SCE's wholesale transmission rates. This Schedule is discussed in Section X of my testimony.

Schedule 31 (HVLV): This schedule calculates the High and Low Voltage Gross Plant percentages. This Schedule is discussed in Mr. Moon's testimony, Exhibit SCE-9.

Schedule 32 (GrossLoad): This schedule presents the forecast load used in calculating retail and wholesale transmission rates. This Schedule is discussed in Section X of my testimony.

Schedule 33 (RetailRates): This schedule calculates retail transmission rates. This Schedule is discussed in Mr. Thomas' testimony, Exhibit SCE-16.

Schedule 34 (UnfundedReserves): This schedule calculates the Unfunded Reserves component of Rate Base. This schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

XIII. SCE'S PROPOSED RETAIL AND WHOLESALE BASE TRRS AND RATES EFFECTIVE JANUARY 1, 2018

Q. What is SCE's proposed retail Base TRR effective June 12, 2019?

A. It is $1,328,294,741, as shown on Line 86 of Schedule 1 of the Formula Rate Spreadsheet (Exhibit SCE-4).

Q. What is SCE's proposed Wholesale Base TRR effective June 12, 2019?

A. It is $1,322,194,021, as shown on Line 89 of Schedule 1 of the Formula Rate Spreadsheet (Exhibit SCE-4).

Q. What are SCE's proposed Base retail transmission rates effective June 12, 2019?

A. SCE's proposed Base retail transmission rates are as developed on Schedule 33 of the populated Formula Rate Spreadsheet, Exhibit SCE-4.

Q. What are SCE's proposed Base Wholesale transmission rates effective June 12, 2019?

A. SCE's proposed Base Wholesale transmission rates are as developed on Schedule 30 of the populated Formula Rate Spreadsheet, Exhibit SCE-4. The proposed rates are as follows:

High Voltage Existing Contracts Access Charge: $7.39 per kW-month
High Voltage Utility Specific Rate: $0.0138426 per kWh
Low Voltage Access Charge: $0.00045 per kWh

Q. Does this complete your testimony?

A. Yes.

DECLARATION

I, Berton J. Hansen, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 5, 2019 in Rosemead, California

Berton J. Hansen

Berton J. Hansen

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

<u>EXHIBIT SCE-4</u>

EXHIBIT TO THE TESTIMONY OF MR. BERTON J. HANSEN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

Exhibit No. SCE-4

Populated Formula Rate Spreadsheet
with Proposed Base TRR and Associated Rates

TO2019A

Attachment 2 to Appendix IX

Formula Rate Spreadsheet

Table of Contents

Overview of SCE Retail Base TRR

SCE's retail Base Transmission Revenue Requirement is the sum of the following components:

TRR Component	Amount
Prior Year TRR	$1,258,035,095
Incremental Forecast Period TRR	$132,737,261
True-Up Adjustment	-$62,477,615
Cost Adjustment	$0
Base TRR (retail)	$1,328,294,741

These components represent the following costs that SCE incurs:

1) The Prior Year TRR component is the TRR associated with the Prior Year (most recent calendar year). The Prior Year TRR is calculated using End-of-Year Rate Base values, as set forth in the "1-BaseTRR" Worksheet.

2) The Incremental Forecast Period TRR is the component of Base TRR associated with forecast additions to in-service plant or CWIP, as set forth in the "2-IFPTRR" Worksheet.

3) The True Up Adjustment is a component of the Base TRR that reflects the difference between projected and actual costs, as set forth in the "3-TrueUpAdjust" Worksheet.

4) The Cost Adjustment component may be included as provided in the Tariff protocols.

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	2017 Value
RATE BASE				
1	ISO Transmission Plant		6-PlantInService, Line 19	$8,573,445,553
2	General Plant + Electric Miscellaneous Intangible Plant		6-PlantInService, Line 27	$266,256,631
3	Transmission Plant Held for Future Use		11-PHFU, Line 8	$9,942,155
4	Abandoned Plant		12-AbandonedPlant, Line 3	$0
	Working Capital amounts			
5	Materials and Supplies		13-WorkCap, Line 16	$14,314,526
6	Prepayments		13-WorkCap, Line 36	$13,703,824
7	Cash Working Capital		(Line 66 + Line 67) / 8	$16,239,768
8	Working Capital		Line 5 + Line 6 + Line 7	$44,258,118
	Accumulated Depreciation Reserve Balances			
9	Transmission Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 13, Col. 12	-$1,633,677,100
10	Distribution Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 16, Col. 5	$0
11	General + Intangible Plant Depreciation Reserve	Negative amount	8-AccDep, Line 26	-$104,458,767
12	Accumulated Depreciation Reserve		Line 9 + Line 10 + Line 11	-$1,738,135,867
13	Accumulated Deferred Income Taxes	Negative amount	9-ADIT, Line 5, Col. 2	-$1,649,088,770
14	CWIP Plant		14-IncentivePlant, L 12, Col 1	$221,778,480
15	Other Regulatory Assets/Liabilities		23-RegAssets, Line 14	$0
16	Unfunded Reserves		34-UnfundedReserves, Line 6	-$10,717,922
17	Network Upgrade Credits	Negative amount	22-NUCs, Line 4	-$93,345,105
18	Rate Base		L1 + L2 + L3 + L4 + L8 + L12 + L13 + L14+ L15+ L16 + L17	$5,624,393,273
OTHER TAXES				
19	Sub-Total Local Taxes	FF1 263.1, Row 30, Column i	FF1 263 or 263.x (see note to left)	$298,376,268
20	Transmission Plant Allocation Factor		27-Allocators, Line 22	19.1484%
21	Property Taxes		Line 19 * Line 20	$57,134,356
22	Payroll Taxes Expense			
23	FICA		Line 24 + Line 25+ Line 26	$106,921,364
24	Fed Ins Cont Amt -- Current	FF1 263, Row 6, Column i	FF1 263 or 263.x (see note to left)	$106,811,420
25	FICA/OASDI Emp Incntv.	FF1 263, Row 7, Column i	FF1 263 or 263.x (see note to left)	$80,115
26	FICA/HIT Emp Incntv.	FF1 263, Row 8, Column i	FF1 263 or 263.x (see note to left)	$29,829
27	CA SUI Current	FF1 263, Row 21, Column i	FF1 263 or 263.x (see note to left)	$5,909,370
28	Fed Unemp Tax Act- Current	FF1 263, Row 9, Column i	FF1 263 or 263.x (see note to left)	$2,620,285
29	CADI Vol Plan Assess	FF1 263.1, Row 1, Column i	FF1 263 or 263.x (see note to left)	$1,555,582
30	SF Pyrl Exp Tx - SCE	FF1 263, Row 39, Column i	FF1 263 or 263.x (see note to left)	$42,940
31	Total Electric Payroll Tax Expense		Line 23 + (Line 27 to Line 30)	$117,049,541
32	Capitalized Overhead portion of Electric Payroll Tax Expense		26-TaxRates, Line 16	$46,585,717
33	Remaining Electric Payroll Tax Expense to Allocate		Line 31 - Line 32	$70,463,824
34	Transmission Wages and Salaries Allocation Factor		27-Allocators, Line 9	6.0143%
35	Payroll Taxes Expense		Line 33 * Line 34	$4,237,931
36	Other Taxes	Note 1	Line 21 + Line 35	$61,372,287

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	2017 Value
	RETURN AND CAPITALIZATION CALCULATIONS			
	Debt			
37	Long Term Debt Amount		5-ROR-1, Line 13	$10,746,567,193
38	Cost of Long Term Debt		Line 37 * Line 39	$519,339,121
39	Long Term Debt Cost Percentage		5-ROR-3, Line 12	4.8326%
	Preferred Stock			
40	Preferred Stock Amount		5-ROR-1, Line 17	$2,224,620,929
41	Cost of Preferred Stock		Line 40 * Line 42	$126,985,860
42	Preferred Stock Cost Percentage		5-ROR-4, Line 9	5.7082%
	Equity			
43	Common Stock Equity Amount		5-ROR-1, Line 23	$12,575,222,880
44	Total Capital		Line 37 + Line 40 + Line 43	$25,546,411,002
	Capital Percentages			
45	Long Term Debt Capital Percentage		Line 37 / Line 44	42.0668%
46	Preferred Stock Capital Percentage		Line 40 / Line 44	8.7082%
47	Common Stock Capital Percentage		Line 43 / Line 44	49.2250%
			Line 45 + Line 46+ Line 47	100.0000%
	Annual Cost of Capital Components			
48	Long Term Debt Cost Percentage		Line 39	4.8326%
49	Preferred Stock Cost Percentage		Line 42	5.7082%
50	Return on Common Equity	Note 2	SCE Return on Equity	17.62%
	Calculation of Cost of Capital Rate			
51	Weighted Cost of Long Term Debt		Line 39 * Line 45	2.0329%
52	Weighted Cost of Preferred Stock		Line 42 * Line 46	0.4971%
53	Weighted Cost of Common Stock		Line 47 * Line 50	8.6734%
54	Cost of Capital Rate		Line 51 + Line 52 + Line 53	11.2034%
55	Equity Rate of Return Including Common and Preferred Stock	Used for Tax calculation	Line 52 + Line 53	9.1705%
56	Return on Capital: Rate Base times Cost of Capital Rate		Line 18 * Line 54	$630,126,059
	INCOME TAXES			
57	Federal Income Tax Rate		26-Tax Rates, Line 1	21.0000%
58	State Income Tax Rate		26-Tax Rates, Line 8	8.8400%
59	Composite Tax Rate	= F + [S * (1 - F)]	(L57 + L58) - (L57 * L58)	27.9836%
	Calculation of Credits and Other:			
60	Amortization of Excess Deferred Tax Liability	Note 3		$200
61	Investment Tax Credit Flowed Through	Note 3		-$520,000
62	South Georgia Income Tax Adjustment	Note 3		$2,606,000
63	Credits and Other		Line 60 + Line 61+ Line 62	$2,086,200
64	Income Taxes:		Formula on Line 65	$204,691,114
65	Income Taxes = [((RB * ER) + D) * (CTR/(1 – CTR))] + CO/(1 – CTR)			
	Where:			
	RB = Rate Base		Line 18	
	ER = Equity Rate of Return Including Common and Preferred Stock		Line 55	
	CTR = Composite Tax Rate		Line 59	
	CO = Credits and Other		Line 63	
	D = Book Depreciation of AFUDC Equity Book Basis		SCE Records	$3,535,511

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	2017 Value
PRIOR YEAR TRANSMISSION REVENUE REQUIREMENT				
	Component of Prior Year TRR:			
66	O&M Expense		19-OandM, Line 91, Col. 6	$77,531,619
67	A&G Expense		20-AandG, Line 23	$52,386,525
68	Network Upgrade Interest Expense		22-NUCs, Line 8	$6,116,851
69	Depreciation Expense		17-Depreciation, Line 70	$241,415,721
70	Abandoned Plant Amortization Expense		12-AbandonedPlant, Line 1	$0
71	Other Taxes		Line 36	$61,372,287
72	Revenue Credits	Negative amount	21-Revenue Credits, Line 44	-$58,832,606
73	Return on Capital		Line 56	$630,126,059
74	Income Taxes		Line 64	$204,691,114
75	Gains and Losses on Trans. Plant Held for Future Use -- Land	Gain negative, loss positive	11-PHFU, Line 10	$0
76	Amortization and Regulatory Debits/Credits		23-RegAssets, Line 16	$0
77	Prior Year Incentive Adder		15-IncentiveAdder, Line 14	$28,785,307
78	Total without FF&U		Sum of Lines 66 to 77	$1,243,592,877
79	Franchise Fees Expense		L 78 * FF Factor (28-FFU, L 5)	$11,448,143
80	Uncollectibles Expense		L 78 * U Factor (28-FFU, L 5)	$2,994,074
81	Prior Year TRR		Line 78 + Line 79+ Line 80	$1,258,035,095
TOTAL BASE TRANSMISSION REVENUE REQUIREMENT				
	Calculation of Base Transmission Revenue Requirement			
82	Prior Year TRR		Line 81	$1,258,035,095
83	Incremental Forecast Period TRR		2-IFPTRR, Line 82	$132,737,261
84	True Up Adjustment		3-TrueUpAdjust, Line 30	-$62,477,615
85	Cost Adjustment	Note 4		$0
86	Base Transmission Revenue Requirement (Retail)	For Retail Purposes	L 82 + L 83 + L 84 + L 85	$1,328,294,741
	Wholesale Base Transmission Revenue Requirement			
87	Base TRR (Retail)		Line 86	$1,328,294,741
88	Wholesale Difference to the Base TRR		25-WholesaleDifference, Line 45	-$6,100,719
89	Wholesale Base Transmission Revenue Requirement		Line 87 + Line 88	$1,322,194,021

Notes:

1) Any amount of "Sub-Total Local Taxes" or "Payroll Taxes Expense" may be excluded if appropriate with the provision of a workpaper showing the reason for the exclusion and the amount of the exclusion.

2) No change in Return on Common Equity will be made absent a Section 205 filing at the Commission.
Does not include any project-specific ROE adders.
In the event that the Return on Common Equity is revised from the initial value, enter cite to Commission Order approving the revised ROE on following line.
Order approving revised ROE:

3) No change in the South Georgia Income Tax Adjustment "Credits and Other" term will be made absent a filing at the Commission. Investment Tax Credit Flowed Through amount shall be negative $520,000 through the Prior Year of 2018, negative $183,000 for the Prior Year of 2019, and $0 thereafter.

4) Cost Adjustment may be included as provided in the Tariff protocols.

Calculation of Incremental Forecast Period TRR ("IFPTRR")

The IFP TRR is equal to the sum of:
1) Forecast Plant Additions * AFCR
2) Forecast Period Incremental CWIP * AFCR for CWIP

1) Calculation of Annual Fixed Charge Rates:

Line			
	a) Annual Fixed Charge Rate for CWIP ("AFCRCWIP")		
1			
2	AFCRCWIP represents the return and income tax costs associated with $1 of CWIP,		
3	expressed as a percent.		
4			
5	AFCRCWIP = CLTD + (COS * (1/(1 - CTR)))		
6			
7	where:		
8	CLTD = Weighted Cost of Long Term Debt		
9	COS = Weighted Cost of Common and Preferred Stock		
10	CTR = Composite Tax Rate		
11			**Reference**
12	Wtd. Cost of Long Term Debt:	2.033%	1-BaseTRR, Line 51
13	Wtd. Cost of Common + Pref. Stock:	9.171%	1-BaseTRR, Line 55
14	Composite Tax Rate:	27.984%	1-BaseTRR, Line 59
15			
16	AFCRCWIP =	14.767%	Line 12 + (Line 13 * (1/(1 - Line 14)))
17			
18	**b) Annual Fixed Charge Rate ("AFCR")**		
19			
20	The AFCR is calculated by dividing the Prior Year TRR (without CWIP related costs)		
21	by Net Plant:		
22			
23	AFCR = (Prior Year TRR - CWIP-related costs) / Net Plant		
24			
25	**Determination of Net Plant:**		
26			**Reference**
27	Transmission Plant - ISO:	$8,573,445,553	6-PlantInService, Line 13
28	Distribution Plant - ISO:	$0	6-PlantInService, Line 16
29	Transmission Dep. Reserve - ISO:	$1,633,677,100	8-AccDep, Line 13
30	Distribution Dep. Reserve - ISO:	$0	8-AccDep, Line 16
31	Net Plant:	$6,939,768,453	(L27 + L28) - (L29 + L30)
32			
33	**Determination of Prior Year TRR without CWIP related costs:**		
34			
35	**a) Determination of CWIP-Related Costs**		
36	**1) Direct (without ROE adder) CWIP costs**		
37	CWIP Plant - Prior Year:	$221,778,480	10-CWIP, L 13 C1
38	AFCRCWIP:	14.767%	Line 16
39	Direct CWIP Related Costs:	$32,749,727	Line 37 * Line 38
40			
41	**2) CWIP ROE Adder costs:**		
42	IREF:	$6,835	15-IncentiveAdder, Line 3
43			
44	Tehachapi CWIP Amount:	$150,976	10-CWIP, Line 13
45	Tehachapi ROE Adder %:	1.25%	15-IncentiveAdder, Line 5
46	Tehachapi ROE Adder $:	$1,290	Formula on Line 52
47			
48	DCR CWIP Amount:	$0	10-CWIP, Line 13
49	DCR ROE Adder %:	1.00%	15-IncentiveAdder, Line 6
50	DCR ROE Adder $:	$0	Formula on Line 52
51			
52	ROE Adder $ = (CWIP/$1,000,000) * IREF * (ROE Adder/1%)		
53			
54	CWIP Related Costs wo FF&U:	$32,751,017	Line 39 + Line 46 + Line 50
55	FF&U Expenses:	$380,347	(28-FFU, L5 FF Factor + U Factor) * L54
56	CWIP Related Costs with FF&U:	$33,131,365	Line 54 + Line 55
57			

58	**b) Determination of AFCR:**		
59			
60	CWIP Related Costs wo FF&U:	$32,751,017	Line 54
61	Prior Year TRR wo FF&U:	$1,243,592,877	1-BaseTRR, Line 78
62	Prior Year TRR wo CWIP Related Costs:	$1,210,841,860	Line 61 - Line 60
63	75% of O&M and A&G in Prior Year TRR:	$97,438,608	(1-BaseTRR, Line 66 + Line 67) * .75
64	AFCR:	16.044%	(Line 62 - Line 63) / Line 31
65			
66	**2) Calculation of IFP TRR**		
67			
68			**Reference**
69	Forecast Plant Additions:	$540,379,822	16-PlantAdditions, L 25, C10
70	AFCR:	16.044%	Line 64
71	AFCR * Forecast Plant Additions:	$86,697,511	Line 69 * Line 70
72			
73	Forecast Period Incremental CWIP:	$301,458,237	10-CWIP, L 54, C8
74	AFCRCWIP:	14.767%	Line 16
75	AFCRCWIP * FP Incremental CWIP:	$44,515,929	Line 73 * Line 74
76			
77	IFPTRR without FF&U:	$131,213,440	Line 71 + Line 75
78			
79	Franchise Fees Expense:	$1,207,912	Line 77 * FF (from 28-FFU, L 5)
80	Uncollectibles Expense:	$315,909	Line 77 * U (from 28-FFU, L 5)
81			
82	Incremental Forecast Period TRR:	$132,737,261	Line 77 + Line 79 + Line 80

Calculation of True Up Adjustment Component of TRR

1) Summary of True Up Adjustment calculation:

a) Attribute True Up TRR to months in the Prior Year (see Note #1) to determine "Monthly True Up TRR" for each month (see Note #2).
b) Determine monthly retail transmission revenues attributable to this formula transmission rate received during Prior Year.
c) Compare costs in (a) to revenues in (b) on a monthly basis and determine "Cumulative Excess (-) or Shortfall (+) in Revenue with Interest".
d) Include previous Annual Update Cumulative Excess or Shortfall in Prior Year (from Previous Annual Update Line 23)
and any One-Time Adjustments in Column 4 (Lines 11 and 12 respectively).
e) Continue interest calculation through the end of the Prior Year (Line 23) to determine Cumulative Excess or Shortfall for this Annual Update.

2) Comparison of True Up TRR and Actual Retail Transmission Revenues received during the Prior Year,
Including previous Annual Update Cumulative Excess or Shortfall in Revenue.

Line										
1		True Up TRR:	$937,389,972	Source:	From 4-TUTRR,	Line 46				
2										
3		**Col 1**	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**	**Col 8**	**Col 9**
4	Calculations:		See Note 2	See Note 3	See Note 4	= C2 - C3 + C 4	See Note 5	See Note 6	See Note 7	=C7 + C8
5					**One-Time**			**Cumulative**		
6					**Adjustments and**			**Excess (-) or**		**Cumulative**
7				**Actual**	**Shortfall/Excess**	**Monthly**		**Shortfall (+)**		**Excess (-) or**
8			**Monthly**	**Retail Base**	**Revenue In**	**Excess (-) or**	**Monthly**	**in Revenue**	**Interest**	**Shortfall (+)**
9			**True Up**	**Transmission**	**Previous**	**Shortfall (+)**	**Interest**	**wo Interest for**	**for Current**	**in Revenue**
10	**Month**	**Year**	**TRR**	**Revenues**	**Annual Update**	**in Revenue**	**Rate**	**Current Month**	**Month**	**with Interest**
11	December	2016	---	---	$56,501,075	$56,501,075	---	$56,501,075	---	$56,501,075
12	January	2017	$78,115,831	$88,876,406	$137,652	-$10,622,923	0.29%	$45,878,152	$148,450	$46,026,602
13	February	2017	$78,115,831	$76,214,394		$1,901,437	0.29%	$47,928,039	$136,234	$48,064,273
14	March	2017	$78,115,831	$88,623,013		-$10,507,182	0.29%	$37,557,091	$124,151	$37,681,242
15	April	2017	$78,115,831	$83,996,142		-$5,880,311	0.31%	$31,800,931	$107,697	$31,908,629
16	May	2017	$78,115,831	$92,695,249		-$14,579,418	0.31%	$17,329,210	$76,319	$17,405,529
17	June	2017	$78,115,831	$104,845,652		-$26,729,821	0.31%	-$9,324,292	$12,526	-$9,311,766
18	July	2017	$78,115,831	$123,594,050		-$45,478,219	0.33%	-$54,789,985	-$105,768	-$54,895,753
19	August	2017	$78,115,831	$125,785,396		-$47,669,565	0.33%	-$102,565,318	-$259,811	-$102,825,129
20	September	2017	$78,115,831	$106,851,758		-$28,735,927	0.33%	-$131,561,056	-$386,737	-$131,947,793
21	October	2017	$78,115,831	$100,653,472		-$22,537,641	0.35%	-$154,485,434	-$501,258	-$154,986,692
22	November	2017	$78,115,831	$88,159,107		-$10,043,276	0.35%	-$165,029,968	-$560,029	-$165,589,997
23	December	2017	$78,115,831	$89,149,113	$78,692,427	$67,659,145	0.35%	-$97,930,853	-$461,161	-$98,392,014

24 **4) True Up Adjustment**

Line			Notes:	
25			**Notes:**	
26	Shortfall or Excess Revenue in Prior Year:	-$98,392,014	Line 23, Column 9	
27	Previous Annual Update TU Adjustment:	$ (39,617,212)	Previous Annual Update Schedule 3, Line 30	Previous Annual Update: Docket No. ER18-169
28	TU Adjustment without Projected Interest	-$58,774,802	Line 26 - Line 27	
29	Projected Interest to Rate Year Mid-Point:	-$3,702,813	Line 28 * (Line 23, Column 6) * 18 months	
30	True Up Adjustment:	-$62,477,615	Line 28 + Line 29. Positive amount is to be collected by SCE (included in Base TRR as a positive amount).	
31			Negative amount is to be returned to customers by SCE (included in Base TRR as a negative amount).	

32 **5) Final True Up Adjustment**
33 The Final True Up Adjustment begins on the month after the last True Up Adjustment and extends through the termination date of
34 this formula transmission rate.
35 The Final True Up Adjustment shall be calculated as above, with interest to the termination date of the Formula Transmission Rate.
36

37 **Partial Year TRR Attribution Allocation Factors:**

Line	Month	Partial Year TRR AAF	Note:
40	January	6.376%	See Note 2.
41	February	5.655%	
42	March	7.183%	
43	April	8.224%	
44	May	8.018%	
45	June	8.945%	
46	July	9.891%	
47	August	10.141%	
48	September	10.218%	
49	October	9.179%	
50	November	7.530%	
51	December	8.640%	
52	Total:	100.000%	

54 **Transmission Revenues: (Note 8)**

Line	Prior Year Month	Col 1 See Note 9 Actual Retail Base Transmission Revenues	Col 2 See Note 10 Other Transmission	Col 3 Distribution	Col 4 Generation	Col 5 Public Purpose	Col 6 Other	Col 7 Sum of left Monthly Total Retail Revenue
63	Jan	$88,876,406	-$7,087,025	$363,695,814	$311,346,758	$49,601,040	$51,035,736	$857,468,728
64	Feb	$76,214,394	-$6,699,589	$307,753,182	$259,118,518	$36,338,088	$47,178,057	$719,902,650
65	Mar	$88,623,013	-$7,723,146	$356,417,097	$297,947,007	$38,088,669	$54,002,238	$827,354,879
66	Apr	$83,996,142	-$7,536,484	$188,886,686	$282,082,099	$37,109,156	$51,830,193	$636,367,793
67	May	$92,695,249	-$8,104,572	$355,261,646	$311,024,347	$43,230,142	$56,581,146	$850,687,959
68	Jun	$104,845,652	-$12,956,109	$402,432,158	$527,362,392	$45,581,306	$64,335,180	$1,131,600,579
69	Jul	$123,594,050	-$19,621,540	$460,524,056	$644,206,334	$73,983,882	$77,772,627	$1,360,459,409
70	Aug	$125,785,396	-$18,661,552	$472,206,916	$682,290,749	$79,884,679	$78,382,836	$1,419,889,024
71	Sep	$106,851,758	-$15,843,048	$396,942,806	$580,474,930	$62,680,552	$65,928,576	$1,197,035,573
72	Oct	$100,653,472	-$15,014,567	$247,390,825	$390,764,399	$42,021,234	$61,154,923	$826,970,286
73	Nov	$88,159,107	-$13,029,919	$343,372,179	$293,271,394	$40,310,842	$53,305,059	$805,388,662
74	Dec	$89,149,113	-$13,623,612	$351,130,269	$301,056,365	$38,410,019	$55,407,794	$821,529,949
75	Totals:	$1,169,443,752	-$145,901,162	$4,246,013,634	$4,880,945,294	$587,239,607	$716,914,366	$11,454,655,492

77 "Total Sales to Ultimate Consumers" from FERC Form 1 Page 300, Line 10, Column b: $11,454,655,492

Instructions:

1) Enter applicable years on Column 1, Lines 11-23 (Prior Year and December of the year previous to the Prior Year).
2) Enter Previous Annual Update True Up Adjustment (if any) on Line 27.
Enter with the same sign as in previous Annual Update. If there is no Previous Annual Update True Up Adjustment, then enter $0.
3) Enter monthly interest rates in accordance with interest rate specified in the regulations of FERC at
18 C.F.R. §35.19a on lines 12 to 23, Column 6.
4) Enter any One Time Adjustments on Column 4, Line 12 (or other appropriate). If SCE is owed enter as positive, if SCE is to return to customers enter as negative.
One Time Adjustments include:
a) In the event that a Commission Order revises SCE's True Up TRR for a previous Prior Year,
SCE shall include that difference in the True Up Adjustment, including interest, at the first opportunity, in accordance with tariff protocols.
Entering on Line 12 (or other appropriate) ensures these One Time Adjustments are recovered from or returned to customers.
b) Any refunds attributable to SCE's previous CWIP TRR cases (Docket Nos. ER08-375, ER09-187, ER10-160, and ER11-1952), not previously returned to customers.
c) Amounts resulting from input errors impacting the True Up TRR in a previous Formula Rate Annual Update pursuant to Protocol Section 3(d)(8).
5) Fill in matrix of all retail revenues from Prior Year in table on lines 63 to 74.
6) Enter Total Sales to Ultimate Consumers on line 77 and verify that it equals the total on line 75.
7) If true up period is less than entire calendar year, then adjust calculation accordingly by including $0 Monthly True Up TRR and $0
Actual Retail Base Transmission Revenues for any months not included in True Up Period.

Notes:

1) The true up period is the portion (all or part) of the Prior Year for which the Formula Transmission Rate was in effect.
2) The Monthly True Up TRR is derived by multiplying the annual True Up TRR on Line 1 by 1/12, if formula was in effect. In the event of
a Partial Year True Up, use the Partial Year TRR Attribution Allocation Factors on Lines 40 to 51 for each month of Partial Year True Up.
Only enter in the Prior Year, Lines 12 to 23, or portion of year formula was in effect in case of Partial Year True Up.
Partial Year True Up Allocation Factors calculated based on three years (2008-2010) of monthly SCE retail base transmission revenues.
3) "Actual Retail Base Transmission Revenues" are SCE retail transmission revenues attributable to this formula transmission rate.
as shown on Lines 63 to 74, Column 1.
4) Enter "Shortfall or Excess Revenue in Previous Annual Update" on Line 11, or other appropriate (from Previous Annual Update, Line 23, Column 9).
5) Monthly Interest Rates in accordance with interest rate specified in the regulations of FERC (See Instruction #3).
6) "Cumulative Excess (-) or Shortfall (+) in Revenue wo Interest for Current Month" is, beginning for the January month,
the amount in Column 9 for previous month plus the current month amount in Column 5. For the first December, it is the amount in Column 5.
7) Interest for Current Month is calculated on average of beginning and ending balances (Column 9 previous month and Column 7 current month).
No interest is applied for the first December.
8) Only provide if formula was in effect during Prior Year.
9) Only include Base Transmission Revenue attributable to this formula transmission rate.
Any other Base Transmission Revenue or refunds is included in "Other".
The Base Transmission Revenues shown in Column 1 shall be reduced to reflect any retail customer refunds provided by SCE associated with the
formula transmission rate that are made through a CPUC-authorized mechanism.
10) Other Transmission Revenue includes the following:
a) Transmission Revenue Balancing Account Adjustment revenue.
b) Transmission Access Charge Balancing Account Adjustment.
c) Reliability Services Revenue.
d) Any Base Transmission Revenue not attributable to this formula.

Calculation of True Up TRR

A) Rate Base for True Up TRR

Line	Rate Base Item	Calculation Method	Notes	FERC Form 1 Reference or Instruction	Amount
1	ISO Transmission Plant	13-Month Avg.		6-PlantInService, Line 18	$8,389,794,318
2	General + Elec. Misc. Intangible Plant	BOY/EOY Avg.		6-PlantInService, Line 24	$269,354,228
3	Transmission Plant Held for Future Use	BOY/EOY Avg.		11-PHFU, Line 9	$9,942,155
4	Abandoned Plant	BOY/EOY Avg.		12-AbandonedPlant Line 4	$0
	Working Capital Amounts				
5	Materials and Supplies	13-Month Avg.		13-WorkCap, Line 17	$13,950,875
6	Prepayments	13-Month Avg.		13-WorkCap, Line 33	$11,375,902
7	Cash Working Capital	1/8 (O&M + A&G)		1-Base TRR Line 7	$16,239,768
8	Working Capital			Line 5 + Line 6 + Line 7	$41,566,545
	Accumulated Depreciation Reserve Amounts				
9	Transmission Depreciation Reserve - ISO	13-Month Avg.	Negative amount	8-AccDep, Line 14, Col. 12	-$1,551,618,145
10	Distribution Depreciation Reserve - ISO	BOY/EOY Avg.	Negative amount	8-AccDep, Line 17, Col. 5	$0
11	G + I Depreciation Reserve	BOY/EOY Avg.	Negative amount	8-AccDep, Line 23	-$109,889,267
12	Accumulated Depreciation Reserve			Line 9 + Line 10 + Line 11	-$1,661,507,412
13	Accumulated Deferred Income Taxes	Prorata Avg.		9-ADIT, Line 15	-$1,595,958,946
14	CWIP Plant	13-Month Avg.		14-IncentivePlant, L 12, C2	$111,914,471
15	Network Upgrade Credits	BOY/EOY Avg.	Negative amount	22-NUCs, Line 7	-$106,562,330
16	Unfunded Reserves			34-UnfundedReserves, Line 7	-$10,860,907
17	Other Regulatory Assets/Liabilities	BOY/EOY Avg.		23-RegAssets, Line 15	$0
18	Rate Base			L1+L2+L3+L4+L8+L12+ L13+L14+L15+L16+L17	$5,447,682,122

B) Return on Capital

Line			Notes	Reference	Amount
19	Cost of Capital Rate		See Instruction 1	Instruction 1, Line j	7.3541%
20	Return on Capital: Rate Base times Cost of Capital Rate			Line 18 * Line 19	$400,625,477

C) Income Taxes

Line		Notes	Reference	Amount
21	Income Taxes = [((RB * ER) + D) * (CTR/(1 – CTR))] + CO/(1 – CTR)			$116,909,385
	Where:			
22	RB = Rate Base		Line 18	$5,447,682,122
23	ER = Equity ROR inc. Com. and Pref. Stock	Instruction 1	Instruction 1, Line k	5.3211%
24	CTR = Composite Tax Rate		1-Base TRR L 59	27.9836%
25	CO = Credits and Other		1-Base TRR L 63	$2,086,200
26	D = Book Depreciation of AFUDC Equity Book Basis		1-Base TRR L 65	$3,535,511

D) True Up TRR Calculation

27	O&M Expense	1-Base TRR L 66	$77,531,619
28	A&G Expense	1-Base TRR L 67	$52,386,525
29	Network Upgrade Interest Expense	1-Base TRR L 68	$6,116,851
30	Depreciation Expense	1-Base TRR L 69	$241,415,721
31	Abandoned Plant Amortization Expense	1-Base TRR L 70	$0
32	Other Taxes	1-Base TRR L 71	$61,372,287
33	Revenue Credits	1-Base TRR L 72	-$58,832,606
34	Return on Capital	Line 20	$400,625,477
35	Income Taxes	Line 21	$116,909,385
36	Gains and Losses on Transmission Plant Held for Future Use -- Land	1-Base TRR L 75	$0
37	Amortization and Regulatory Debits/Credits	1-Base TRR L 76	$0
38	Total without True Up Incentive Adder	Sum Line 27 to Line 37	$897,525,259
39	True Up Incentive Adder	15-IncentiveAdder L 20	$29,103,495
40	True Up TRR without Franchise Fees and Uncollectibles Expense included:	Line 38 + Line 39	$926,628,754

E) Calculation of final True Up TRR with Franchise Fees and Uncollectibles Expenses

Line			Reference:
41	True Up TRR wo FF:	$926,628,754	Line 40
42	Franchise Fee Factor:	0.921%	28-FFU, L 5
43	Franchise Fee Expense:	$8,530,266	Line 41 * Line 42
44	Uncollectibles Expense Factor:	0.241%	28-FFU, L 5
45	Uncollectibles Expense:	$2,230,951	Line 41 * Line 44
46	True Up TRR:	$937,389,972	L 41 + L 43 + L 45

Instructions:

1) Use weighted average (by time) of the Return on Equity in effect during the Prior Year in determining the "Cost of Capital Rate" on Line 19 and the "Equity Rate of Return Including Preferred Stock" on Line 23 in the event that the ROE is revised during the Prior Year. In this event, the ROE used in Schedule 1 will differ from the ROE used in this Schedule 4, because the Schedule 1 ROE will be the most recent ROE, whereas the Schedule 4 Cost of Capital Rate and Equity Rate of Return including Com. + Pref. Stock will be based on the weighted-average ROE.

Calculation of weighted average Cost of Capital Rate in Prior Year:

If ROE does not change during year, then attribute all days to Line a "ROE at end of Prior Year" and none to "ROE at start of PY"

		Percentage	Reference:	From	To		Days ROE In Effect
a	ROE at end of Prior Year	9.80%	See Line e below	Jan 1, 2017	Dec 31, 2017		365
b	ROE start of Prior Year	9.80%	See Line f below				
c						Total days in year:	365
d	Wtd. Avg. ROE in Prior Year	9.80%	((Line a ROE * Line a days) + (Line b ROE * Line b days)) / Total Days in Year				

Commission Decisions approving ROE:

		Reference:
e	End of Prior Year	Settlement in ER11-3697
f	Beginning of Prior Year	Settlement in ER11-3697

		Percentage	Reference:
g	Wtd. Cost of Long Term Debt	2.0329%	1-Base TRR L 51
h	Wtd.Cost of Preferred Stock	0.4971%	1-Base TRR L 52
i	Wtd.Cost of Common Stock	4.8241%	1-Base TRR L 47 * Line d
j	Cost of Capital Rate	7.3541%	Sum of Lines g to i

Calculation of Equity Rate of Return Including Common and Preferred Stock:

	Percentage	Reference:
k	5.3211%	Sum of Lines h to i

Calculation of Components of Cost of Capital Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	2017 Value
	RETURN AND CAPITALIZATION CALCULATIONS			
	Calculation of Long Term Debt Amount			
1	Bonds -- Account 221	13-month avg.	5-ROR-2, Line 1	$10,684,345,055
2	Less Reacquired Bonds -- Account 222	13-month avg.	5-ROR-2, Line 2	-$40,384,615
3	Long Term Debt Advances from Associated Companies -- Account 223	13-month avg.	5-ROR-2, Line 3	$0
4	Other Long Term Debt -- Account 224	13-month avg.	5-ROR-2, Line 4	$424,282,124
5	Unamortized Premium on Long Term Debt - Account 225	13-month avg.	5-ROR-2, Line 5	$6,680,027
6	Less Unamortized Discount on Long Term Debt -- Account 226	13-month avg.; enter negative	5-ROR-2, Line 6	-$33,623,700
7	Unamortized Debt Expenses -- Account 181	13-month avg.; enter negative	5-ROR-2, Line 7	-$83,307,522
8	Unamortized Loss on Reacquired Debt -- Account 189	13-month avg.; enter negative	5-ROR-2, Line 8	-$176,083,211
9	Composite Tax Rate		1-BaseTRR, Line 59	27.98%
10	After tax amount of Unamortized Loss on Reacquired Debt		Line 8 * (1- Line 9)	-$126,808,790
11	Removal of Long Term Debt Related to Fuel Inventories	13-month avg.; enter negative	5-ROR-2, Line 9	-$84,615,385
12	Adjustments related to "LT Debt Related to Fuel Inventories"		5-ROR-2, Line 10	$0
13	Long Term Debt Amount		Sum of Lines 1 to 7 and 10 to 12	$10,746,567,193
	Calculation of Preferred Stock Amount			
14	Preferred Stock Amount -- Account 204	13-month avg.	5-ROR-2, Line 11	$2,281,594,181
15	Unamortized Issuance Costs	13-month avg.	5-ROR-2, Line 12	-$44,042,736
16	Net Gain (Loss) From Purchase and Tender Offers	13-month avg.	5-ROR-2, Line 13	-$12,930,516
17	Preferred Stock Amount		Sum of Lines 14 to 16	$2,224,620,929
	Calculation of Common Stock Equity Amount			
18	Total Proprietary Capital	13-month avg.	5-ROR-2, Lines 14 + 14a	$14,822,803,188
19	Less Preferred Stock Amount -- Account 204	Same as L 14, but negative	5-ROR-2, Line 11	-$2,281,594,181
20	Minus Net Gain (Loss) From Purchase and Tender Offers	Same as L 16, but reverse sign	5-ROR-2, Line 13	$12,930,516
21	Less Unappropriated Undist. Sub. Earnings -- Acct. 216.1	13-month avg.	5-ROR-2, Line 15	$2,603,770
22	Less Accumulated Other Comprehensive Loss -- Account 219	13-month avg.	5-ROR-2, Line 16	$18,479,587
23	Common Stock Equity Amount		Sum of Lines 18 to 22	$12,575,222,880

Calculation of 13-Month Average Capitalization Balances
Year 2017

Line	Item	Col 1 13-Month Avg. = Sum (Cols. 2-14)/13	Col 2 December	Col 3 January	Col 4 February	Col 5 March	Col 6 April	Col 7 May	Col 8 June	Col 9 July	Col 10 August	Col 11 September	Col 12 October	Col 13 November	Col 14 December
	Bonds -- Account 221 (Note 1):														
1		$10,684,345,055	$10,296,542,857	$10,431,542,857	$10,392,257,143	$10,957,257,143	$10,957,257,143	$10,557,257,143	$10,557,257,143	$10,857,257,143	$10,817,971,429	$10,817,971,429	$10,817,971,429	$10,717,971,429	$10,717,971,429
	Reacquired Bonds -- Account 222 (Note 2): enter - of FF1														
2		-$40,384,615	-$165,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000
	Long Term Debt Advances from Associated Companies (Note 3):														
3		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Other Long Term Debt -- Account 224 (Note 4):														
4		$424,282,124	$306,621,506	$471,616,306	$471,611,083	$606,605,839	$606,600,572	$606,595,284	$606,589,973	$306,584,639	$306,579,284	$306,573,905	$306,568,504	$306,563,080	$306,557,633
	Unamortized Premium on Long Term Debt -- Account 225 (Note 5)														
5		$6,680,027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,802,461	$21,740,878	$21,679,295	$21,617,712
	Less Unamortized Discount on Long Term Debt -- Account 226 (Note 6): enter - of FF1														
6		-$33,623,700	-$34,304,356	-$34,124,678	-$33,976,130	-$34,268,167	-$34,093,163	-$33,909,673	-$33,738,132	-$33,554,761	-$33,377,305	-$33,205,764	-$33,022,393	-$32,855,820	-$32,677,760
	Unamortized Debt Expenses -- Account 181 (Note 7): enter - of FF1														
7		-$83,307,522	-$78,466,386	-$79,500,131	-$78,931,113	-$85,565,223	-$84,846,360	-$84,197,371	-$83,548,381	-$84,336,533	-$83,662,293	-$85,916,773	-$85,238,764	-$84,577,795	-$84,210,666
	Unamortized Loss on Reacquired Debt -- Account 189 (Note 8): enter - of FF1														
8		-$176,083,211	-$184,457,795	-$183,057,531	-$181,657,268	-$180,257,004	-$178,856,740	-$177,456,477	-$176,056,213	-$174,655,949	-$173,255,685	-$171,920,046	-$170,519,600	-$169,119,154	-$167,812,285
	Removal of Long Term Debt Not Financing Rate Base (Note 9)														
9		-$84,615,385	-$100,000,000	-$100,000,000	-$100,000,000	-$100,000,000	-$100,000,000	-$100,000,000	-$100,000,000	-$100,000,000	-$100,000,000	-$100,000,000	-$100,000,000	$0	$0
	Adjustments related to "LT Debt Not Financing Rate Base" (Note 10)														
10		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Preferred Stock Amount -- Account 204 (Note 11):														
11		$2,281,594,181	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,720,064,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950
	Unamortized Issuance Costs (Note 12)														
12		-$44,042,736	-$43,904,550	-$43,612,325	-$43,320,100	-$43,027,875	-$42,735,649	-$42,443,424	-$54,784,211	-$54,456,894	-$41,423,177	-$41,138,642	-$40,854,108	-$40,569,573	-$40,285,039
	Net Gain (Loss) From Purchase and Tender Offers (Note 13):														
13		-$12,930,516	-$7,396,211	-$7,345,987	-$7,295,763	-$7,195,315	-$7,145,091	-$7,145,091	-$7,094,867	-$19,793,826	-$19,708,188	-$19,622,550	-$19,536,911	-$19,451,273	-$19,365,634
	Total Proprietary Capital (Note 14):														
14		$14,822,803,188	$14,482,786,817	$14,615,648,032	$14,509,372,060	$14,623,685,111	$14,705,023,359	$14,808,546,334	$15,195,168,410	$14,852,851,255	$14,841,775,399	$14,993,193,820	$15,128,682,538	$15,267,986,011	$14,671,722,293
	Proprietary Capital Adjustment for Wildfire Related Capital														
14a		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Unappropriated Undist. Sub. Earnings -- Acct. 216.1 (Note 15): enter - of FF1														
15		$2,603,770	$2,603,436	$2,603,437	$2,603,437	$2,603,437	$2,603,437	$2,604,191	$2,604,191	$2,604,191	$2,604,191	$2,604,050	$2,604,050	$2,603,481	$2,603,481
	Accumulated Other Comprehensive Loss -- Account 219 (Note 16): enter - of FF1														
16		$18,479,587	$20,446,907	$19,981,024	$19,515,140	$17,543,914	$18,734,452	$18,250,527	$18,131,535	$17,647,610	$18,713,013	$18,000,214	$17,516,289	$17,032,364	$18,721,643

Instructions:

1) Enter 13 months of balances for capital structure for Prior Year and December previous to Prior Year in Columns 2-14.
Beginning and End of year amounts in Columns 2 and 14 are from FERC Form 1, as referenced in below notes.

Notes:

1) Amount in Column 2 from FF1 112.18d, amount in Column 14 from FF1 112.18c, amounts in columns 3-13 from SCE internal records.
2) Amount in Column 2 from FF1 112.19d, amount in Column 14 from FF1 112.19c, amounts in columns 3-13 from SCE internal records.
3) Amount in Column 2 from FF1 112.20d, amount in Column 14 from FF1 112.20c, amounts in columns 3-13 from SCE internal records.
4) Amount in Column 2 from FF1 112.21d, amount in Column 14 from FF1 112.21c, amounts in columns 3-13 from SCE internal records.
5) Amount in Column 2 from FF1 112.22d, amount in Column 14 from FF1 112.22c, amounts in columns 3-13 from SCE internal records.
6) Amount in Column 2 from FF1 112.23d, amount in Column 14 from FF1 112.23c, amounts in columns 3-13 from SCE internal records.
7) Amount in Column 2 from FF1 111.69d, amount in Column 14 from FF1 111.69c, amounts in columns 3-13 from SCE internal records.
8) Amount in Column 2 from FF1 111.81d, amount in Column 14 from FF1 111.81c, amounts in columns 3-13 from SCE internal records.
9) Amounts in Columns 2-14 are from SCE internal records.
10) Amounts in Columns 2-14 are from SCE internal records.
11) Amount in Column 2 from FF1 112.3d, amount in Column 14 from FF1 112.3c, amounts in columns 3-13 from SCE internal records.
12) Amounts in Columns 2-14 are from SCE internal records.
13) Amounts in Columns 2-14 are from SCE internal records.
14) Amount in Column 2 from FF1 112.16d, amount in Column 14 from FF1 112.16c, amounts in columns 3-13 from SCE internal records.
14a) Represents Capital disclosed by SCE related to Wildfire Related Capital, not yet paid on a cash basis. Amounts in Columns 2-14 are from SCE internal records
15) Amount in Column 2 from FF1 112.12d, amount in Column 14 from FF1 112.12c, amounts in columns 3-13 from SCE internal records.
16) Amount in Column 2 from FF1 112.15d, amount in Column 14 from FF1 112.15c, amounts in columns 3-13 from SCE internal records.

Long Term Debt Cost Percentage

Prior Year: 2017

1) Calculation of "Long Term Debt Cost Percentage"

Line		Amount	Reference
1	Total Annual Cost of Outstanding Series Debt:	$508,780,232	Line 200, Col 10
2	Total Annual Amortized Loss on Reacquired Debt:	$16,710,267	FF1 117.64c
3	Total Annual Cost of Debt:	$525,490,499	= L1 + L2
4			
5	Total "Principal Amount Outstanding" Debt:	$11,024,708,633	Line 200, Col 5
6	Total Reacquired Debt:	-$30,000,000	Line 205, Col 5
7	Total Unamortized Loss on Reacquired Debt:	-$167,812,285	5-ROR-2, Line 8, Col. 14 (Negative of FF1 111.81c)
8	Composite Tax Rate:	27.9836%	1-BaseTRR, Line 59
9	After-Tax Total Unamortized Loss on Reacquired Debt:	-$120,852,366	= L7 * (1 - L8)
10	Total Debt Balance:	$10,873,856,267	= L5 + L6 + L9
11			
12	Long Term Debt Cost Percentage:	4.8326%	= L3 / L10

2) Long Term Debt Information for each Outstanding Series

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	
	FF1 256, Col a	FF1 256, Col d	FF1 256, Col e	FF1 256, Col a	FF1 257, Col h	Note 1	FF1 256, Col c Note 2	= Col 5 - Col 7	Note 3	= Col 5 * Col 9	
Line	Series	Date of Offering	Maturity Date	Coupon Rate	Principal Amount Outstanding ($000s)	Amort-ization Period (Years)	Net Discount & Issuance Cost ($000s)	Net Proceeds ($000s)	Cost of Money	Annual Cost ($000s)	Comments: See below
101	Series 2004B	1/14/2004	1/15/2034	6.000%	$525,000	30.0	$8,280	$516,720	6.115%	$32,106	
102	Series 2004G	3/23/2004	4/1/2035	5.750%	$350,000	31.0	$3,217	$346,784	5.814%	$20,350	
103	Series 2005B	1/19/2005	1/15/2036	5.550%	$250,000	31.0	$3,074	$246,926	5.634%	$14,086	
104	Series 2005E	6/27/2005	7/15/2035	5.350%	$350,000	30.0	$3,231	$346,770	5.413%	$18,944	
105	Series 2006A	1/31/2006	2/1/2036	5.625%	$350,000	30.0	$4,288	$345,713	5.711%	$19,988	
106	Series 2006E	12/11/2006	1/15/2037	5.550%	$400,000	30.0	$6,176	$393,824	5.658%	$22,630	
107	Series 2008A	1/22/2008	2/1/2038	5.950%	$600,000	30.0	$9,110	$590,890	6.060%	$36,363	
108	Series 2008B	8/18/2008	8/15/2018	5.500%	$400,000	10.0	$5,522	$394,478	5.683%	$22,731	
109	Series 2009A	3/20/2009	3/15/2039	6.050%	$500,000	30.0	$8,470	$491,530	6.175%	$30,874	
110	Series 2010A	3/11/2010	3/15/2040	5.500%	$500,000	30.0	$11,365	$488,635	5.658%	$28,291	
111	Series 2010B	8/30/2010	9/1/2040	4.500%	$500,000	30.0	$8,505	$491,495	4.605%	$23,026	
112	Series 2011A	5/17/2011	6/1/2021	3.875%	$500,000	10.0	$7,170	$492,830	4.051%	$20,254	
113	Series 2011E	11/12/2011	12/1/2041	3.900%	$250,000	30.0	$4,118	$245,883	3.995%	$9,987	
114	Series 2012A	3/13/2012	3/15/2042	4.050%	$400,000	30.0	$9,028	$390,972	4.183%	$16,731	
115	Series 2013A	3/7/2013	3/15/2043	3.900%	$400,000	30.0	$6,710	$393,290	3.996%	$15,986	
116	Series 2013C	10/2/2013	10/1/2023	3.500%	$600,000	10.0	$6,269	$593,731	3.626%	$21,753	
117	Series 2013D	10/2/2013	10/1/2043	4.650%	$800,000	30.0	$13,852	$786,148	4.759%	$38,072	
118	Series 2014B	5/9/2014	5/1/2017	N/A	N/A	3.0	N/A	N/A	N/A	N/A	1
119	Series 2014C	11/7/2014	11/1/2017	N/A	N/A	3.0	N/A	N/A	N/A	N/A	2
120	Series 2015A	1/26/2015	2/1/2022	1.845%	$353,751	7.0	$4,452	$349,299	2.039%	$7,212	
121	Series 2015B	1/26/2015	2/1/2022	2.400%	$325,000	7.0	$2,668	$322,332	2.529%	$8,218	
122	Series 2015C	1/26/2015	2/1/2045	3.600%	$425,000	30.0	$6,310	$418,690	3.682%	$15,649	
123	Series 2017A	3/24/2017	4/1/2047	4.000%	$1,000,000	30.0	-$10,736	$1,010,736	3.939%	$39,387	
124	SONGS_2006A	4/5/2013	4/1/2028	1.375%	$157,500	15.0	$977	$156,523	1.421%	$2,238	
125	SONGS_2006B	4/5/2013	4/1/2028	1.900%	$38,500	15.0	$325	$38,175	1.965%	$757	
126	SONGS 2006C&D	4/12/2006	11/1/2033	2.625%	$135,000	28.0	$2,490	$132,510	2.720%	$3,671	
127	CLARK COUNTY 2010	4/1/2015	6/1/2031	1.875%	$75,000	16.0	$874	$74,126	1.960%	$1,470	
128	4CRNRS 2011	4/1/2015	4/1/2029	1.875%	$55,540	14.0	$995	$54,545	2.023%	$1,123	
129	Series PV2000AB	3/1/2004	6/1/2035	5.000%	$144,400	31.0	$1,300	$143,100	5.058%	$7,304	
130	Series 4CRNRS 05AB	4/1/2015	4/1/2029	1.875%	$203,460	14.0	$2,271	$201,189	1.967%	$4,001	
131	SONGS 2010A	9/21/2010	9/1/2029	4.500%	$100,000	19.0	$2,000	$98,000	4.660%	$4,660	
132	CPCFA SONGS 2011	9/1/2011	9/1/2031	0.796%	$30,000	20.0	$350	$29,650	0.860%	$258	3
133	CPCFA SONGS 2011	9/1/2011	9/1/2031	N/A	N/A	20.0	N/A	N/A	N/A	N/A	4
134	6.65% Notes	4/1/1999	4/1/2029	6.650%	$300,000	30.0	$4,827	$295,173	6.776%	$20,328	
135	Ft. Irwin Loan	9/1/2003	9/1/2053	5.060%	$6,558	50.0	$0	$6,558	5.060%	$332	
136											
137	…										

Comments for Section 2 "Long Term Debt Information for each Outstanding Series":

Comment #:	Comment
1	Bond matured in 2017.
2	Fuel Bond matured in 2017.
3	FF1 has the variable rate. 0.796% is based on 2017 average.
4	Reacquired series are shown below in Section 3 see line 201
…	

200 **Total Principal Amount Outstanding (sum of above * 1,000):** $11,024,708,633 **Total Annual Cost (sum of above * 1,000):** $508,780,232

3) Long Term Debt Information for each Reacquired Series

	Col 1	Col 2	Col 3	Col 4	Col 5	
	Series	**Date of Offering**	**Maturity Date**	**Coupon Rate**	**Principal Amount ($000s)**	**Comment #**
201	CPCFA SONGS 2011	9/1/2011	9/1/2031	0.407%	-$30,000	
202						
203						
204	…					
205				**Total Principal Amount (sum of above * 1,000):**	-$30,000,000	

Comments for Section 3 "Long Term Debt Information for each Reacquired Series":

Comment #:	Comment

Notes:
1) Equal to maturity date less the date of offering year
2) Sum of all amounts for each issuance
3) 18 CFR 35.13 (22) Statement AV - Rate of Return (ii)(B)(6) Cost of money
4) Excludes debt, or portions thereof, that does not finance Rate Base

Preferred Stock Cost Percentage

Prior Year: 2017

1) Calculation of "Preferred Stock Cost Percentage"

Line		Amount	Reference
1	Total Annual Cost of Preferred Stock:	$126,019,184	Line 112, Col 9
2	Total Reacquired Preferred Stock Cost:	$1,027,661	Line 312, Col 6
3	Total Annual Cost of Preferred:	$127,046,845	= L1 + L2
4			
5	Total Preferred Stock Amount Outstanding:	$2,245,054,950	FF1 112.3c
6	Net Gain (Loss) from Purchase and Tender Offers:	$19,365,634	Line 312, Col 4
7	Total Preferred Balance:	$2,225,689,316	= L5 - L6
8			
9	Preferred Stock Cost Percentage:	5.7082%	= L3 / L7

2) Preferred Stock Information for each Outstanding Series

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	
	FF1 250, Col a	SCE Records	FF1 250, Col a	FF1 251, Col f	Sec 3, Col 2	= Col 4 - Col 5	= Col 6 / Col 4	= Col 3 / Col 7 Note 1	= Col 4 * Col 8	
Line	**Preferred Stock**	**Issue Date**	**Dividend Rate**	**Face Value / Amount Outstanding ($000s)**	**Total Issuance Cost ($000s)**	**Net Proceeds at Issuance ($000s)**	**% of Face Value**	**Cost of Money / Effective Rate**	**Annualized Cost ($000s)**	**Notes**
101	$25 Par Value 4.32% Series	5/8/1947	4.320%	$41,336	-$763	$42,099	101.8%	4.242%	$1,753	
102	$25 Par Value 4.08% Series	5/19/1950	4.080%	$16,250	-$40	$16,290	100.2%	4.070%	$661	
103	$25 Par Value 4.24% Series	2/15/1956	4.240%	$30,000	-$84	$30,084	100.3%	4.228%	$1,268	
104	$25 Par Value 4.78% Series	2/10/1958	4.780%	$32,419	-$50	$32,469	100.2%	4.773%	$1,547	
105	Series E	1/17/2012	6.250%	$350,000	$5,957	$344,043	98.3%	6.483%	$22,689	1
106	Series G	1/29/2013	5.100%	$400,010	$12,972	$387,038	96.8%	5.317%	$21,268	1
107	Series H	3/6/2014	5.750%	$275,010	$6,272	$268,738	97.7%	6.056%	$16,654	1
108	Series J	8/24/2015	5.375%	$325,010	$6,420	$318,590	98.0%	5.635%	$18,313	1
109	Series K	3/8/2016	5.450%	$300,010	$6,960	$293,050	97.7%	5.757%	$17,271	1
110	Series L	6/26/2017	5.000%	$475,010	$12,801	$462,209	97.3%	5.177%	$24,593	1
111	…									
112								**Total Annual Cost (sum of above * 1,000):**	$126,019,184	

3) Preferred Stock Issuance Cost Details for each Outstanding Series

	Col 1	Col 2	Col 3	Col 4
	Same list as in Section 2	SCE Records	SCE Records	
Line	**Preferred Stock**	**Total Issuance Cost ($000s)**	**Full Amortization Period**	**Notes**
201	$25 Par Value 4.32% Series	-$763	30	Fully amortized
202	$25 Par Value 4.08% Series	-$40	30	Fully amortized
203	$25 Par Value 4.24% Series	-$84	30	Fully amortized
204	$25 Par Value 4.78% Series	-$50	30	Fully amortized
205	Series E	$5,957	10	
206	Series G	$12,972	30	Redeemed Series B and C
207	Series H	$6,272	10	
208	Series J	$6,420	10	
209	Series K	$6,960	10	Redeemed Series D
210	Series L	$12,801	30	
211	…			

4) Reacquired Preferred Stock Information

Line	Col 1 SCE Records Preferred Stock	Col 2 SCE Records Call Date	Col 3 SCE Records Total Issuance Cost ($000s)	Col 4 SCE Records Net Gain (Loss) from Purchase and Tender Offers ($000s)	Col 5 SCE Records Amortization Period	Col 6 Col 3 / Col 5 Issuance Amortization Cost ($000s)	Notes
301	8.540% Preferred, premium	11/1/1985	-$287	-$15	34	-$8	Net gain from open-market purchase of 67,400 shares in November 1985
302	12.000% Preferred, redemption	2/1/1986	$6,248	$383	34	$184	Redemption premium paid to holders (so loss to company)
303	12.000% Preferred, redemption	2/1/1986	$1,025	$63	34	$30	Initial issue discount
304	Series A	6/16/2012	$0	$0	5	$0	Fully amortized
305	Series B	2/28/2013	$2,586	$2,170	30	$86	Redeemed by Series G
306	Series C	2/28/2013	$2,887	$2,422	30	$96	Redeemed by Series G
307	Series D	3/31/2016	$2,148	$1,772	10	$215	Series D was redeemed by Series K
308	Series F	7/19/2017	$12,749	$12,572	30	$425	Redeemed by Series L
309							
310							
311	…						
312	**Total Annual Cost (sum of above * 1,000):**			$19,365,634		$1,027,661	

Notes:

1) If issuance costs not fully amortized then the "Cost of Money Effective Rate" is the 18 CFR 35.13 (22) Statement AV - Rate of Return (ii)(B)(6) Cost of money.
If the issuance costs are fully amortized then the "Cost of Money Effective Rate" is equal to Column 3 / Column 7.

Plant In Service

Inputs are shaded yellow

1) Transmission Plant - ISO

Balances for Transmission Plant - ISO during the Prior Year, including December of previous year (See Note 1): Prior Year: **2017**

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12 Sum C2 - C11
Line	**Mo/YR**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
1	Dec 2016	$86,845,703	165,326,927	$531,582,611	$3,249,175,449	$2,233,991,232	$324,258,228	$1,235,903,791	$185,508,197	$81,951,072	$182,027,086	$8,276,570,295
2	Jan 2017	$81,997,511	$165,330,397	$528,854,083	$3,250,037,231	$2,231,001,014	$335,699,493	$1,232,564,516	$185,656,754	$81,997,920	$160,125,968	$8,253,264,889
3	Feb 2017	$82,013,020	$165,784,066	$534,882,418	$3,256,654,353	$2,213,130,982	$339,965,913	$1,235,030,894	$186,119,194	$82,775,424	$161,709,715	$8,258,065,980
4	Mar 2017	$82,413,677	$165,733,853	$532,806,954	$3,260,114,606	$2,225,922,423	$342,740,514	$1,241,178,225	$186,361,377	$83,455,651	$161,453,729	$8,282,181,008
5	Apr 2017	$82,424,960	$165,734,429	$540,340,485	$3,290,596,932	$2,251,979,965	$344,598,339	$1,244,265,048	$186,611,561	$83,540,944	$161,600,158	$8,351,692,820
6	May 2017	$82,438,880	$165,704,351	$548,767,497	$3,303,060,549	$2,258,078,709	$345,368,677	$1,242,476,528	$187,117,539	$83,717,689	$168,349,232	$8,385,079,651
7	Jun 2017	$81,409,531	$165,534,488	$552,041,270	$3,313,909,561	$2,261,350,618	$347,377,534	$1,244,803,717	$188,491,607	$84,190,542	$167,806,375	$8,406,915,244
8	Jul 2017	$81,421,876	$165,199,675	$554,107,049	$3,321,544,471	$2,263,663,368	$350,109,485	$1,244,039,916	$188,624,718	$84,257,050	$167,839,950	$8,420,807,557
9	Aug 2017	$81,875,011	$164,728,138	$558,293,842	$3,350,799,129	$2,265,082,996	$350,778,178	$1,246,103,080	$188,962,876	$84,383,656	$168,194,579	$8,459,201,484
10	Sep 2017	$81,886,831	$164,709,520	$560,085,940	$3,354,129,789	$2,263,017,844	$354,174,067	$1,247,812,337	$189,290,136	$84,485,994	$168,808,262	$8,468,400,720
11	Oct 2017	$81,898,670	$164,708,798	$557,690,365	$3,337,803,870	$2,267,000,466	$357,358,231	$1,247,335,361	$189,937,864	$84,808,333	$169,009,660	$8,457,551,618
12	Nov 2017	$87,866,111	$164,907,957	$559,289,849	$3,340,005,249	$2,268,750,108	$362,445,561	$1,244,772,136	$190,107,796	$84,849,890	$171,154,663	$8,474,149,320
13	Dec 2017	$87,876,203	$164,901,118	$569,698,023	$3,409,447,774	$2,283,380,922	$364,424,080	$1,245,933,686	$190,222,489	$84,920,374	$172,640,885	$8,573,445,553
14	13-Mo. Avg:	$83,259,076	$165,254,132	$548,341,568	$3,310,559,920	$2,252,796,204	$347,638,331	$1,242,478,403	$187,924,008	$83,794,965	$167,747,712	$8,389,794,318

2) Distribution Plant - ISO

Balances for Distribution Plant - ISO for December of Prior Year and year before Prior Year (See Note 2)

	Col 1	Col 2	Col 3	Col 4	Col 5 Sum C2 - C4
Line	**Mo/YR**	**360**	**361**	**362**	**Total**
15	Dec 2016	$0	$0	$0	$0
16	Dec 2017	$0	$0	$0	$0
17	Average:	$0	$0	$0	$0

3) ISO Transmission Plant

ISO Transmission Plant is the sum of "Transmission Plant - ISO" and "Distribution Plant - ISO"

Line		Amount	Source
18	Average value:	$8,389,794,318	Sum of Line 14, Col 12 and Line 17, Col 5
19	EOY Value:	$8,573,445,553	Sum of Line 13, Col 12 and Line 16, Col 5

4) General Plant + Electric Miscellaneous Intangible Plant ("G&I Plant")

General and Intangible Plant is an allocated portion of Total G&I Plant based on the Trans. W&S Allocation Factor

Line	Note 1 Prior Year Month	Data Source	Col 1 General Plant Balances	Col 2 Intangible Plant Balances	Col 3 Total G&I Plant Balances	Notes
20	December	FF1 206.99.b and 204.5b	$2,941,903,413	$1,588,136,353	$4,530,039,766	BOY amount from previous PY
21	December	FF1 207.99.g and 205.5g	$3,102,162,333	$1,324,870,316	$4,427,032,649	End of year ("EOY") amount

a) BOY/EOY Average G&I Plant

Line		Amount	Source
22	Average BOY/EOY Value:	$4,478,536,208	Average of Line 20 and 21.
23	Transmission W&S Allocation Factor:	6.0143%	27-Allocators, Line 9
24	General + Intangible Plant:	$269,354,228	Line 22 * Line 23.

b) EOY G&I Plant

Line		Amount	Source
25	EOY Value:	$4,427,032,649	Line 21.
26	Transmission W&S Allocation Factor:	6.0143%	27-Allocators, Line 9
27	General + Intangible Plant:	$266,256,631	Line 25 * Line 26.

Transmission Activity Used to Determine Monthly Transmission Plant - ISO Balances

1) Total Transmission Plant Balances by Account (See Note 3)

Line	Col 1 Mo/YR	Col 2 350.1	Col 3 350.2	Col 4 352	Col 5 353	Col 6 354	Col 7 355	Col 8 356	Col 9 357	Col 10 358	Col 11 359	Col 12 Sum C2 - C11 Total
28	Dec 2016	$129,517,154	$209,428,813	$825,778,508	$5,586,246,880	$2,305,498,226	$1,158,164,968	$1,499,811,260	$253,220,290	$368,734,329	$200,535,234	$12,536,935,662
29	Jan 2017	$131,378,834	$209,432,283	$821,581,817	$5,587,843,440	$2,303,288,695	$1,198,334,409	$1,489,256,987	$253,416,854	$367,637,511	$181,870,488	$12,544,041,318
30	Feb 2017	$131,394,149	$209,885,951	$830,639,899	$5,601,903,856	$2,290,647,334	$1,213,024,813	$1,496,353,590	$253,857,398	$370,873,866	$183,453,263	$12,582,034,119
31	Mar 2017	$131,237,781	$209,952,218	$827,239,561	$5,610,673,607	$2,300,102,274	$1,221,317,311	$1,506,732,163	$253,855,832	$370,602,080	$183,167,786	$12,614,880,613
32	Apr 2017	$131,249,064	$209,952,775	$838,658,330	$5,638,495,922	$2,319,350,719	$1,228,634,538	$1,514,411,786	$253,429,387	$372,129,606	$183,311,693	$12,689,623,820
33	May 2017	$131,262,629	$210,021,495	$847,569,487	$5,656,988,000	$2,324,305,485	$1,231,820,325	$1,513,503,678	$253,935,044	$372,276,466	$190,014,214	$12,731,696,824
34	Jun 2017	$131,656,980	$210,412,890	$852,493,266	$5,682,316,529	$2,326,687,641	$1,238,729,356	$1,517,863,406	$255,114,081	$371,791,118	$189,504,964	$12,776,570,231
35	Jul 2017	$131,669,332	$211,181,935	$855,677,899	$5,699,938,077	$2,328,487,000	$1,248,163,749	$1,515,097,590	$257,612,022	$369,992,617	$189,561,687	$12,807,381,908
36	Aug 2017	$132,122,466	$210,772,635	$862,262,674	$5,767,479,992	$2,329,659,078	$1,250,309,323	$1,520,655,991	$257,719,917	$373,462,880	$189,881,476	$12,894,326,431
37	Sep 2017	$132,134,287	$210,811,380	$865,002,126	$5,775,192,266	$2,327,714,921	$1,257,773,379	$1,524,633,562	$258,054,613	$372,183,869	$190,427,674	$12,913,928,077
38	Oct 2017	$132,146,126	$210,811,077	$861,261,427	$5,736,314,270	$2,330,813,154	$1,268,202,518	$1,523,176,665	$258,218,973	$374,081,690	$190,628,198	$12,885,654,099
39	Nov 2017	$132,141,953	$211,027,940	$863,692,706	$5,741,418,352	$2,332,193,517	$1,285,954,661	$1,521,698,252	$256,220,577	$374,087,950	$192,477,732	$12,910,913,640
40	Dec 2017	$132,152,045	$211,042,975	$879,621,910	$5,902,949,228	$2,343,145,352	$1,292,702,467	$1,524,531,167	$256,348,021	$376,710,004	$193,773,411	$13,112,976,580

2) Total Transmission Activity by Account (See Note 4):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
41	Jan 2017	$1,861,680	$3,470	-$4,196,691	$1,596,560	-$2,209,532	$40,169,441	-$10,554,272	$196,564	-$1,096,818	-$18,664,747	$7,105,655
42	Feb 2017	$15,315	$453,669	$9,058,082	$14,060,416	-$12,641,360	$14,690,403	$7,096,603	$440,544	$3,236,355	$1,582,775	$37,992,801
43	Mar 2017	-$156,368	$66,267	-$3,400,337	$8,769,751	$9,454,939	$8,292,498	$10,378,573	-$1,566	-$271,785	-$285,477	$32,846,494
44	Apr 2017	$11,283	$557	$11,418,768	$27,822,315	$19,248,445	$7,317,227	$7,679,623	-$426,444	$1,527,526	$143,907	$74,743,207
45	May 2017	$13,565	$68,720	$8,911,158	$18,492,078	$4,954,766	$3,185,788	-$908,108	$505,657	$146,860	$6,702,521	$42,073,004
46	Jun 2017	$394,350	$391,396	$4,923,779	$25,328,529	$2,382,156	$6,909,030	$4,359,728	$1,179,037	-$485,348	-$509,250	$44,873,407
47	Jul 2017	$12,352	$769,044	$3,184,633	$17,621,548	$1,799,359	$9,434,393	-$2,765,816	$2,497,941	-$1,798,501	$56,723	$30,811,677
48	Aug 2017	$453,134	-$409,300	$6,584,775	$67,541,915	$1,172,077	$2,145,575	$5,558,400	$107,895	$3,470,262	$319,790	$86,944,523
49	Sep 2017	$11,821	$38,745	$2,739,452	$7,712,274	-$1,944,157	$7,464,055	$3,977,572	$334,696	-$1,279,010	$546,197	$19,601,645
50	Oct 2017	$11,839	-$303	-$3,740,698	-$38,877,996	$3,098,234	$10,429,139	-$1,456,898	$164,361	$1,897,821	$200,525	-$28,273,977
51	Nov 2017	-$4,172	$216,863	$2,431,279	$5,104,081	$1,380,363	$17,752,143	-$1,478,412	-$1,998,396	$6,260	$1,849,534	$25,259,541
52	Dec 2017	$10,092	$15,035	$15,929,204	$161,530,876	$10,951,835	$6,747,806	$2,832,915	$127,444	$2,622,054	$1,295,679	$202,062,940
53	Total:	$2,634,891	$1,614,163	$53,843,402	$316,702,348	$37,647,126	$134,537,499	$24,719,907	$3,127,731	$7,975,675	-$6,761,823	$576,040,918

3) ISO Incentive Plant Balances (See Note 5)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
54	Dec 2016	$18,676,991	$94,873,060	$264,612,613	$1,133,695,495	$1,757,159,286	$151,903,903	$815,549,135	$185,286,763	$79,876,649	$138,148,965	$4,639,782,859
55	Jan 2017	$18,676,518	$94,876,530	$264,645,105	$1,134,003,514	$1,757,105,733	$151,893,376	$815,800,031	$185,437,236	$79,929,256	$138,052,636	$4,640,419,936
56	Feb 2017	$18,691,887	$95,330,199	$264,975,714	$1,135,011,021	$1,758,904,118	$152,004,528	$815,962,417	$185,898,802	$80,694,378	$139,629,836	$4,647,102,900
57	Mar 2017	$18,690,106	$95,315,396	$265,391,800	$1,134,469,788	$1,759,144,819	$152,579,551	$820,004,289	$186,131,259	$81,379,399	$139,175,161	$4,652,281,569
58	Apr 2017	$18,701,390	$95,315,966	$265,618,774	$1,166,956,821	$1,759,588,944	$152,261,118	$820,805,743	$186,354,446	$81,457,429	$139,304,595	$4,686,365,226
59	May 2017	$18,715,053	$95,315,922	$273,135,307	$1,174,877,109	$1,761,384,448	$152,068,596	$818,579,133	$186,860,411	$81,634,324	$145,740,022	$4,708,310,325
60	Jun 2017	$18,714,293	$95,316,683	$273,306,086	$1,174,813,678	$1,761,309,419	$152,124,117	$819,894,933	$188,226,697	$82,112,003	$145,423,584	$4,711,241,494
61	Jul 2017	$18,726,643	$95,317,444	$273,267,755	$1,174,922,189	$1,761,690,976	$152,184,302	$820,127,331	$188,454,165	$82,187,902	$145,613,117	$4,712,491,823
62	Aug 2017	$19,179,777	$94,864,828	$272,944,915	$1,175,321,777	$1,762,179,405	$152,264,271	$820,451,272	$188,783,135	$82,297,670	$145,733,021	$4,714,020,072
63	Sep 2017	$19,191,598	$94,863,648	$272,955,426	$1,175,350,247	$1,760,569,394	$154,038,484	$821,031,819	$189,110,692	$82,406,965	$145,892,023	$4,715,410,295
64	Oct 2017	$19,203,437	$94,863,054	$273,089,481	$1,176,020,630	$1,761,225,260	$154,334,615	$821,042,451	$189,739,134	$82,721,369	$146,087,539	$4,718,326,968
65	Nov 2017	$20,856,532	$95,067,594	$273,124,697	$1,176,034,397	$1,761,585,804	$154,373,423	$817,939,425	$189,822,550	$82,763,105	$146,241,840	$4,717,809,366
66	Dec 2017	$20,866,624	$95,067,405	$273,150,052	$1,176,074,826	$1,762,377,599	$154,450,782	$818,269,307	$189,937,751	$82,820,739	$146,444,294	$4,719,459,379

4) ISO Incentive Plant Activity (See Note 6)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
67	Jan 2017	($472)	$3,470	$32,492	$308,019	($53,553)	($10,526)	$250,896	$150,473	$52,608	($96,329)	$637,077
68	Feb 2017	$15,369	$453,669	$330,610	$1,007,507	$1,798,385	$111,151	$162,386	$461,566	$765,122	$1,577,200	$6,682,963
69	Mar 2017	($1,780)	($14,803)	$416,086	($541,233)	$240,701	$575,024	$4,041,873	$232,457	$685,021	($454,675)	$5,178,669
70	Apr 2017	$11,283	$570	$226,974	$32,487,033	$444,125	($318,433)	$801,454	$223,187	$78,030	$129,434	$34,083,658
71	May 2017	$13,664	($43)	$7,516,533	$7,920,288	$1,795,504	($192,522)	($2,226,610)	$505,965	$176,895	$6,435,427	$21,945,099
72	Jun 2017	($761)	$761	$170,780	($63,431)	($75,029)	$55,521	$1,315,801	$1,366,286	$477,679	($316,437)	$2,931,169
73	Jul 2017	$12,350	$761	($38,332)	$108,511	$381,557	$60,184	$232,398	$227,468	$75,900	$189,532	$1,250,328
74	Aug 2017	$453,134	($452,616)	($322,840)	$399,588	$488,428	$79,970	$323,941	$328,970	$109,768	$119,905	$1,528,249
75	Sep 2017	$11,821	($1,180)	$10,511	$28,470	($1,610,011)	$1,774,213	$580,546	$327,557	$109,294	$159,002	$1,390,223
76	Oct 2017	$11,839	($594)	$134,055	$670,383	$655,866	$296,131	$10,632	$628,442	$314,405	$195,516	$2,916,673
77	Nov 2017	$1,653,095	$204,541	$35,216	$13,767	$360,544	$38,809	($3,103,026)	$83,416	$41,735	$154,301	($517,602)
78	Dec 2017	$10,092	($189)	$25,355	$40,429	$791,795	$77,359	$329,882	$115,202	$57,634	$202,454	$1,650,013
79	Total:	$2,189,633	$194,346	$8,537,439	$42,379,331	$5,218,313	$2,546,880	$2,720,172	$4,650,989	$2,944,091	$8,295,329	$79,676,521

5) Total Transmission Activity Not Including Incentive Plant Activity (See Note 7)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
80	Jan 2017	$1,862,153	$0	-$4,229,183	$1,288,541	-$2,155,979	$40,179,967	-$10,805,168	$46,090	-$1,149,426	-$18,568,418	$6,468,578
81	Feb 2017	-$54	$0	$8,727,472	$13,052,909	-$14,439,745	$14,579,252	$6,934,217	-$21,022	$2,471,233	$5,575	$31,309,838
82	Mar 2017	-$154,588	$81,070	-$3,816,423	$9,310,983	$9,214,239	$7,717,474	$6,336,701	-$234,023	-$956,806	$169,199	$27,667,825
83	Apr 2017	$0	-$13	$11,191,794	-$4,664,717	$18,804,320	$7,635,660	$6,878,169	-$649,632	$1,449,496	$14,473	$40,659,549
84	May 2017	-$98	$68,763	$1,394,625	$10,571,790	$3,159,263	$3,378,310	$1,318,502	-$308	-$30,035	$267,094	$20,127,905
85	Jun 2017	$395,111	$390,635	$4,752,999	$25,391,960	$2,457,185	$6,853,509	$3,043,928	-$187,249	-$963,027	-$192,813	$41,942,238
86	Jul 2017	$2	$768,283	$3,222,965	$17,513,038	$1,417,802	$9,374,209	-$2,998,213	$2,270,474	-$1,874,401	-$132,809	$29,561,349
87	Aug 2017	$0	$43,317	$6,907,615	$67,142,326	$683,649	$2,065,605	$5,234,459	-$221,076	$3,360,494	$199,885	$85,416,274
88	Sep 2017	$0	$39,925	$2,728,941	$7,683,804	-$334,146	$5,689,843	$3,397,025	$7,139	-$1,388,305	$387,196	$18,211,422
89	Oct 2017	$0	$291	-$3,874,754	-$39,548,378	$2,442,368	$10,133,009	-$1,467,530	-$464,081	$1,583,416	$5,009	-$31,190,650
90	Nov 2017	-$1,657,268	$12,322	$2,396,063	$5,090,314	$1,019,819	$17,713,334	$1,624,614	-$2,081,812	-$35,475	$1,695,232	$25,777,143
91	Dec 2017	$0	$15,224	$15,903,849	$161,490,447	$10,160,039	$6,670,447	$2,503,033	$12,242	$2,564,420	$1,093,225	$200,412,927
92	Total:	$445,258	$1,419,817	$45,305,963	$274,323,018	$32,428,813	$131,990,619	$21,999,736	-$1,523,258	$5,031,585	-$15,057,152	$496,364,397

6) Total Monthly Transmission Activity as a Percent of Annual Transmission Activity (See Note 8

	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359
93	Jan 2017	418.2%	0.0%	-9.3%	0.5%	-6.6%	30.4%	-49.1%	-3.0%	-22.8%	123.3%
94	Feb 2017	0.0%	0.0%	19.3%	4.8%	-44.5%	11.0%	31.5%	1.4%	49.1%	0.0%
95	Mar 2017	-34.7%	5.7%	-8.4%	3.4%	28.4%	5.8%	28.8%	15.4%	-19.0%	-1.1%
96	Apr 2017	0.0%	0.0%	24.7%	-1.7%	58.0%	5.8%	31.3%	42.6%	28.8%	-0.1%
97	May 2017	0.0%	4.8%	3.1%	3.9%	9.7%	2.6%	6.0%	0.0%	-0.6%	-1.8%
98	Jun 2017	88.7%	27.5%	10.5%	9.3%	7.6%	5.2%	13.8%	12.3%	-19.1%	1.3%
99	Jul 2017	0.0%	54.1%	7.1%	6.4%	4.4%	7.1%	-13.6%	-149.1%	-37.3%	0.9%
100	Aug 2017	0.0%	3.1%	15.2%	24.5%	2.1%	1.6%	23.8%	14.5%	66.8%	-1.3%
101	Sep 2017	0.0%	2.8%	6.0%	2.8%	-1.0%	4.3%	15.4%	-0.5%	-27.6%	-2.6%
102	Oct 2017	0.0%	0.0%	-8.6%	-14.4%	7.5%	7.7%	-6.7%	30.5%	31.5%	0.0%
103	Nov 2017	-372.2%	0.9%	5.3%	1.9%	3.1%	13.4%	7.4%	136.7%	-0.7%	-11.3%
104	Dec 2017	0.0%	1.1%	35.1%	58.9%	31.3%	5.1%	11.4%	-0.8%	51.0%	-7.3%

4) Calculation of change in Non-Incentive ISO Plant:

A) Change in ISO Plant Balance December to December (See Note 9)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
105	$1,030,500	-$425,809	$38,115,412	$160,272,325	$49,389,689	$40,165,853	$10,029,896	$4,714,292	$2,969,302	-$9,386,201	$296,875,259

B) Change in Incentive ISO Plant (See Note 10)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
106	$2,189,633	$194,346	$8,537,439	$42,379,331	$5,218,313	$2,546,880	$2,720,172	$4,650,989	$2,944,091	$8,295,329	$79,676,521

C) Change in Non-Incentive ISO Plant (See Note 11)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
107	-$1,159,134	-$620,155	$29,577,973	$117,892,994	$44,171,377	$37,618,973	$7,309,724	$63,303	$25,211	-$17,681,529	$217,198,738

5) Other ISO Transmission Activity without Incentive Plant Activity (See Note 12):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
108	Jan 2017	-$4,847,719	$0	-$2,761,020	$553,763	-$2,936,665	$11,451,792	-$3,590,170	-$1,915	-$5,759	-$21,804,789	-$23,942,483
109	Feb 2017	$141	$0	$5,697,725	$5,609,615	-$19,668,417	$4,155,269	$2,303,992	$874	$12,382	$6,547	-$1,881,872
110	Mar 2017	$402,437	-$35,410	-$2,491,550	$4,001,486	$12,550,740	$2,199,576	$2,105,459	$9,726	-$4,794	$198,689	$18,936,359
111	Apr 2017	$0	$6	$7,306,557	-$2,004,708	$25,613,417	$2,176,258	$2,285,369	$26,997	$7,263	$16,996	$35,428,155
112	May 2017	$256	-$30,035	$910,480	$4,543,330	$4,303,240	$962,860	$438,091	$13	-$150	$313,647	$11,441,732
113	Jun 2017	-$1,028,588	-$170,623	$3,102,993	$10,912,442	$3,346,939	$1,953,336	$1,011,388	$7,782	-$4,825	-$226,419	$18,904,423
114	Jul 2017	-$5	-$335,575	$2,104,111	$7,526,399	$1,931,192	$2,671,766	-$996,199	-$94,356	-$9,392	-$155,957	$12,641,985
115	Aug 2017	$0	-$18,920	$4,509,632	$28,855,070	$931,200	$588,723	$1,739,223	$9,187	$16,838	$234,724	$36,865,679
116	Sep 2017	$0	-$17,439	$1,781,588	$3,302,190	-$455,142	$1,621,676	$1,128,710	-$297	-$6,956	$454,682	$7,809,012
117	Oct 2017	$0	-$127	-$2,529,631	-$16,996,301	$3,326,756	$2,888,034	-$487,608	$19,286	$7,934	$5,882	-$13,765,775
118	Nov 2017	$4,314,345	-$5,382	$1,564,268	$2,187,612	$1,389,098	$5,048,521	$539,801	$86,516	-$178	$1,990,702	$17,115,304
119	Dec 2017	$0	-$6,650	$10,382,819	$69,402,096	$13,839,018	$1,901,161	$831,668	-$509	$12,849	$1,283,768	$97,646,221
120	Total:	-$1,159,134	-$620,155	$29,577,973	$117,892,994	$44,171,377	$37,618,973	$7,309,724	$63,303	$25,211	-$17,681,529	$217,198,738

Notes:

1) Amounts on Line 13 from corresponding account Schedule 7, column 2.
Amounts on Line 1 must match corresponding account Schedule 7, Column 2 for previous year.
The amounts for each month on the remaining lines are calculated by summing the following values:
a) Other ISO Transmission Activity without Incentive Plant Activity on Lines 108-119 for the same month;
b) ISO Incentive Plant Activity on Lines 67 to 78 for the same month; and
c) The previous month balance of the Transmission Plant - ISO amounts on Lines 1-13.
For instance, the amount for May of the Prior Year (on Line 6) for Account 353 (Column 5) is the sum of the following values:
a) the "Other ISO Transmission Activity without Incentive Plant Activity" for May of the Prior Year (on Line 112, Column 5);
b) the "ISO Incentive Plant Activity" for May of the Prior Year (on Line 71, Column 5),
c) and the "Transmission Plant - ISO" amount for April of the Prior Year (on Line 5, Column 5).
2) Amounts on Line 15 must match 6-Plant Study amounts for Distribution Plant - ISO for previous year.
Amounts on Line 16 must match amounts on 6-PlantStudy for Distribution Plant - ISO.
3) Reconciles to BOY and EOY FERC Form 1 (FF1 207, Lines 48-56 , Column g).
4) Includes recorded Transmission Plant-In-Service additions, retirements, transfers and adjustments. From SCE internal acounting records.
5) Includes balances for SCE Incentive Projects.
6) Monthly differences from previous matrix. Other columns from SCE internal accounting records.
7) Amount in matrix on lines 41 to 52 minus amount in matrix on lines 67 to 78
8) Amount in "Total Transmission Activity Not Including Incentive Plant Activity" matrix divided by Total on Line 92 for each account/month.
9) Amount on Line 13 less amount on Line 1 for each account.
10) Line 79
11) Amount on Line 105 less amount on Line 106 for each account.
12) For each column (FERC Account) divide Line 107 by Line 92 to arrive at a ratio for each column.
Apply the ratio of each column to each monthly value from Lines 80-91 to calculate the values for
the corresponsing months listed in Lines 108-119.

Transmission Plant Study

Input cells are shaded yellow

A) Plant Classified as Transmission in FERC Form 1 for Prior Year: Prior Year: 2017

Line	Account	Col 1 Total Plant	Data Source	Col 2 Transmission Plant - ISO	Col 3 ISO % of Total	Notes
1						
2	**Substation**					
3	352	$879,621,910	FF1 207.49g	$569,698,023	64.77%	
4	353	$5,902,949,228	FF1 207.50g	$3,409,447,774	57.76%	
5	**Total Substation**	$6,782,571,138	L 3 + L 4	$3,979,145,796	58.67%	
6						
7	**Land**					
8	350	$343,195,020	FF1 207.48g	$252,777,321	73.65%	
9						
10	**Total Substation and Land**	$7,125,766,158	L 5 + L 8	$4,231,923,117	59.39%	
11						
12	**Lines**					
13	354	$2,343,145,352	FF1 207.51g	$2,283,380,922	97.45%	
14	355	$1,292,702,467	FF1 207.52g	$364,424,080	28.19%	
15	356	$1,524,531,167	FF1 207.53g	$1,245,933,686	81.73%	
16	357	$256,348,021	FF1 207.54g	$190,222,489	74.20%	
17	358	$376,710,004	FF1 207.55g	$84,920,374	22.54%	
18	359	$193,773,411	FF1 207.56g	$172,640,885	89.09%	
19	**Total Lines**	$5,987,210,422	Sum L13 to L18	$4,341,522,436	72.51%	
20						
21	**Total Transmission**	**$13,112,976,580**	L 10 + L 19	**$8,573,445,553**	**65.38%**	Note 1

B) Plant Classified as Distribution in FERC Form 1:

Line	Account	Total Plant	Data Source	Distribution Plant - ISO	ISO % of Total	
22						
23	**Land:**					
24	360	$125,242,449	FF1 207.60g	$0	0.00%	
25	**Structures:**					
26	361	$644,469,720	FF1 207.61g	$0	0.00%	
27	362	$2,539,477,720	FF1 207.62g	$0	0.00%	
28	**Total Structures**	$3,183,947,440	L 26 + L 27	$0	0.00%	
29						
30	**Total Distribution**	**$3,309,189,889**	L 24 + L 28	**$0**	**0.00%**	Note 2

Notes:

1) Total transmission does not include account 359.1 "Asset Retirement Costs for Transmission Plant"
Total on this line is also equal to FF1 207.58g (Total Transmission Plant)
less FF1 207.57g (Asset Retirement Costs for Transmission Plant).
2) Only accounts 360-362 included as there is no ISO plant in any other Distribution accounts.

Instructions:

1) Perform annual Transmission Study pursuant to instructions in tariff.
2) Enter total amounts of plant from FERC Form 1 in Column 1, "Total Plant".
3) Enter ISO portion of plant in Column 2, "Transmission Plant - ISO, or "Distribution Plant - ISO".

Accumulated Depreciation Reserve

Input cells are shaded yellow

1) Transmission Depreciation Reserve - ISO

Prior Year: 2017

Balances for Transmission Depreciation Reserve - ISO during the Prior Year, including December of previous year (See Note 1):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
		FERC Account:										=Sum C2 to C11
Line	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
1	Dec 2016	$0	$18,079,939	$72,260,283	$439,653,028	$465,353,602	$46,058,792	$407,738,326	$839,659	$2,896,108	$14,910,822	$1,467,790,558
2	Jan 2017	$0	$18,308,641	$72,968,804	$446,340,019	$470,658,390	$43,293,011	$424,670,241	$1,097,968	$2,966,994	$15,230,980	$1,495,535,050
3	Feb 2017	$0	$18,537,348	$74,988,694	$453,020,610	$480,300,559	$42,956,299	$418,952,853	$1,351,770	$3,647,254	$15,439,119	$1,509,194,507
4	Mar 2017	$0	$18,752,244	$75,746,245	$459,717,422	$481,542,497	$43,274,320	$414,004,345	$1,591,257	$3,753,210	$15,648,580	$1,514,030,121
5	Apr 2017	$0	$18,981,512	$78,025,130	$466,431,065	$479,419,455	$43,608,479	$408,380,385	$1,801,902	$4,266,251	$15,858,405	$1,516,772,583
6	May 2017	$0	$19,198,531	$79,324,141	$473,196,866	$482,881,386	$44,346,449	$409,860,084	$2,058,471	$4,530,617	$16,067,284	$1,531,463,829
7	Jun 2017	$0	$19,358,181	$80,982,622	$479,978,025	$486,603,968	$44,761,789	$409,133,074	$2,302,614	$4,638,565	$16,287,005	$1,544,045,843
8	Jul 2017	$0	$19,450,337	$82,492,567	$486,786,988	$490,700,722	$44,947,546	$416,123,576	$2,721,167	$4,594,687	$16,505,751	$1,564,323,342
9	Aug 2017	$0	$19,671,148	$84,381,528	$493,577,188	$495,061,770	$45,825,131	$412,604,760	$2,965,008	$5,431,862	$16,723,044	$1,576,241,439
10	Sep 2017	$0	$19,891,911	$85,854,639	$500,468,911	$499,785,591	$46,365,836	$411,436,308	$3,225,333	$5,470,400	$16,939,955	$1,589,438,884
11	Oct 2017	$0	$20,119,708	$86,660,238	$507,400,304	$503,523,455	$46,501,420	$416,480,842	$3,453,030	$6,009,297	$17,159,383	$1,607,307,678
12	Nov 2017	$0	$20,345,360	$88,098,215	$514,267,081	$507,772,422	$45,937,860	$417,577,655	$3,568,060	$6,276,835	$17,371,471	$1,621,214,958
13	Dec 2017	$0	$20,570,771	$90,912,860	$521,029,731	$508,793,023	$46,422,546	$417,546,825	$3,830,318	$6,981,972	$17,589,054	$1,633,677,100
14	13-Mo. Avg:	$0	$19,328,125	$80,976,613	$480,143,634	$488,645,911	$44,946,114	$414,193,021	$2,369,735	$4,728,004	$16,286,989	$1,551,618,145

2) Distribution Depreciation Reserve - ISO (See Note 2)

	Col 1	Col 2	Col 3	Col 4	Col 5	
		FERC Account:			=Sum C2 to C4	
	Mo/YR	360	361	362	Total	Notes
15	Dec 2016	$0	$0	$0	$0	Beginning of Year ("BOY") amount
16	Dec 2017	$0	$0	$0	$0	End of Year ("EOY") amount
17	BOY/EOY Average:	$0	$0	$0	$0	Average of Line 15 and Line 16

3) General and Intangible Depreciation Reserve

	Col 1	Col 2	Col 3	Col 4	Col 5	
			=C4+C5			
	Mo/YR		Total Gen. and Int. Depreciation Reserve	General Depreciation Reserve	Intangible Depreciation Reserve	Source
18	Dec 2016	BOY:	$1,917,414,678	$1,073,416,375	$843,998,303	FF1 219.28c and 200.21c for previous year
19	Dec 2017	EOY:	$1,736,829,507	$1,094,912,964	$641,916,543	FF1 219.28c and 200.21c
20		BOY/EOY Average:	$1,827,122,093			Average of Line 18 and Line 19

a) Average BOY/EOY General and Intangible Depreciation Reserve

		Amount	Source
21	Total G+I Dep. Reserve on Average BOY/EOY basis:	$1,827,122,093	Line 20
22	Transmission W&S Allocation Factor:	6.0143%	27-Allocators, Line 9
23	G + I Plant Dep. Reserve (BOY/EOY Average):	$109,889,267	Line 21 * Line 22

b) EOY General and Intangible Depreciation Reserve

		Amount	Source
24	Total G+I Dep. Reserve on Average EOY basis:	$1,736,829,507	Line 19
25	Transmission W&S Allocation Factor:	6.0143%	27-Allocators, Line 9
26	G + I Plant Dep. Reserve (EOY):	$104,458,767	Line 24 * Line 25

Transmission Activity Used to Determine Monthly Transmission Depreciation Reserve - ISO Balances

1) ISO Depreciation Expense (See Note 3)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
27	Jan 2017	$0	$228,702	$1,138,473	$6,687,886	$4,542,449	$991,690	$3,141,255	$255,074	$264,292	$236,635	$17,486,456
28	Feb 2017	$0	$228,707	$1,132,629	$6,689,660	$4,536,369	$1,026,681	$3,132,768	$255,278	$264,443	$208,164	$17,474,699
29	Mar 2017	$0	$229,335	$1,145,540	$6,703,280	$4,500,033	$1,039,729	$3,139,037	$255,914	$266,951	$210,223	$17,490,041
30	Apr 2017	$0	$229,265	$1,141,095	$6,710,403	$4,526,042	$1,048,215	$3,154,661	$256,247	$269,144	$209,890	$17,544,962
31	May 2017	$0	$229,266	$1,157,229	$6,773,145	$4,579,026	$1,053,897	$3,162,507	$256,591	$269,420	$210,080	$17,691,161
32	Jun 2017	$0	$229,224	$1,175,277	$6,798,800	$4,591,427	$1,056,253	$3,157,961	$257,287	$269,990	$218,854	$17,755,072
33	Jul 2017	$0	$228,989	$1,182,288	$6,821,131	$4,598,080	$1,062,396	$3,163,876	$259,176	$271,514	$218,148	$17,805,599
34	Aug 2017	$0	$228,526	$1,186,713	$6,836,846	$4,602,782	$1,070,752	$3,161,935	$259,359	$271,729	$218,192	$17,836,833
35	Sep 2017	$0	$227,874	$1,195,679	$6,897,062	$4,605,669	$1,072,797	$3,167,179	$259,824	$272,137	$218,653	$17,916,873
36	Oct 2017	$0	$227,848	$1,199,517	$6,903,917	$4,601,470	$1,083,182	$3,171,523	$260,274	$272,467	$219,451	$17,939,650
37	Nov 2017	$0	$227,847	$1,194,387	$6,870,313	$4,609,568	$1,092,921	$3,170,311	$261,165	$273,507	$219,713	$17,919,730
38	Dec 2017	$0	$228,123	$1,197,812	$6,874,844	$4,613,125	$1,108,479	$3,163,796	$261,398	$273,641	$222,501	$17,943,720
39	Total:	$0	$2,743,707	$14,046,640	$81,567,286	$54,906,038	$12,706,990	$37,886,809	$3,097,586	$3,239,236	$2,610,503	$212,804,795

2) Total Transmission Allocation Factors (See Note 4)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359
40	Jan 2017	418.2%	0.0%	-9.3%	0.5%	-6.6%	30.4%	-49.1%	-3.0%	-22.8%	123.3%
41	Feb 2017	0.0%	0.0%	19.3%	4.8%	-44.5%	11.0%	31.5%	1.4%	49.1%	0.0%
42	Mar 2017	-34.7%	5.7%	-8.4%	3.4%	28.4%	5.8%	28.8%	15.4%	-19.0%	-1.1%
43	Apr 2017	0.0%	0.0%	24.7%	-1.7%	58.0%	5.8%	31.3%	42.6%	28.8%	-0.1%
44	May 2017	0.0%	4.8%	3.1%	3.9%	9.7%	2.6%	6.0%	0.0%	-0.6%	-1.8%
45	Jun 2017	88.7%	27.5%	10.5%	9.3%	7.6%	5.2%	13.8%	12.3%	-19.1%	1.3%
46	Jul 2017	0.0%	54.1%	7.1%	6.4%	4.4%	7.1%	-13.6%	-149.1%	-37.3%	0.9%
47	Aug 2017	0.0%	3.1%	15.2%	24.5%	2.1%	1.6%	23.8%	14.5%	66.8%	-1.3%
48	Sep 2017	0.0%	2.8%	6.0%	2.8%	-1.0%	4.3%	15.4%	-0.5%	-27.6%	-2.6%
49	Oct 2017	0.0%	0.0%	-8.6%	-14.4%	7.5%	7.7%	-6.7%	30.5%	31.5%	0.0%
50	Nov 2017	-372.2%	0.9%	5.3%	1.9%	3.1%	13.4%	7.4%	136.7%	-0.7%	-11.3%
51	Dec 2017	0.0%	1.1%	35.1%	58.9%	31.3%	5.1%	11.4%	-0.8%	51.0%	-7.3%

3) Calculation of Non-Incentive ISO Reserve

A) Change in Depreciation Reserve - ISO (See Note 5)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
52	$0	$2,490,832	$18,652,577	$81,376,703	$43,439,421	$363,754	$9,808,498	$2,990,659	$4,085,865	$2,678,232	$165,886,542

B) Total Depreciation Expense (See Note 6)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
53	$0	$2,743,707	$14,046,640	$81,567,286	$54,906,038	$12,706,990	$37,886,809	$3,097,586	$3,239,236	$2,610,503	$212,804,795

C) Other Activity (See Note 7)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
54	$0	-$252,875	$4,605,937	-$190,582	-$11,466,617	-$12,343,237	-$28,078,311	-$106,926	$846,629	$67,729	-$46,918,253

4) Other Transmission Activity (See Note 8)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
55	Jan 2017	$0	$0	-$429,951	-$895	$762,340	-$3,757,470	$13,790,660	$3,235	-$193,406	$83,523	$10,258,035
56	Feb 2017	$0	$0	$887,260	-$9,068	$5,105,800	-$1,363,394	-$8,850,156	-$1,476	$415,817	-$25	-$3,815,242
57	Mar 2017	$0	-$14,439	-$387,989	-$6,469	-$3,258,095	-$721,707	-$8,087,545	-$16,427	-$160,995	-$761	-$12,654,427
58	Apr 2017	$0	$2	$1,137,791	$3,241	-$6,649,085	-$714,056	-$8,778,622	-$45,601	$243,896	-$65	-$14,802,500
59	May 2017	$0	-$12,247	$141,782	-$7,345	-$1,117,095	-$315,926	-$1,682,807	-$22	-$5,054	-$1,201	-$2,999,915
60	Jun 2017	$0	-$69,573	$483,204	-$17,641	-$868,845	-$640,913	-$3,884,972	-$13,144	-$162,042	$867	-$5,173,058
61	Jul 2017	$0	-$136,834	$327,656	-$12,167	-$501,326	-$876,639	$3,826,626	$159,378	-$315,392	$597	$2,471,900
62	Aug 2017	$0	-$7,715	$702,248	-$46,646	-$241,734	-$193,167	-$6,680,751	-$15,519	$565,447	-$899	-$5,918,736
63	Sep 2017	$0	-$7,111	$277,432	-$5,338	$118,152	-$532,091	-$4,335,631	$501	-$233,600	-$1,742	-$4,719,428
64	Oct 2017	$0	-$52	-$393,919	$27,476	-$863,605	-$947,599	$1,873,012	-$32,577	$266,430	-$23	-$70,856
65	Nov 2017	$0	-$2,195	$243,591	-$3,536	-$360,601	-$1,656,480	-$2,073,498	-$146,134	-$5,969	-$7,625	-$4,012,449
66	Dec 2017	$0	-$2,712	$1,616,832	-$112,193	-$3,592,524	-$623,794	-$3,194,626	$859	$431,497	-$4,917	-$5,481,578
67	Total:	$0	-$252,875	$4,605,937	-$190,582	-$11,466,617	-$12,343,237	-$28,078,311	-$106,926	$846,629	$67,729	-$46,918,253

Notes:

1) Amounts on Line 13 based on current year Plant Study. Amounts on Line 1 shall be based on previous year Plant Study, and shall match amounts on Line 13 in previous year Annual Update.

The amounts for each month on the remaining lines are calculated by summing the following values:

a) Depreciation Expense (on Lines 27 to 38) for the same month;
b) Other Transmission Activity (on Lines 55 to 66) for the same month; and
c) Balances for Transmission Depreciation Reserve (on Lines 1 to 13) for the previous month.

For instance, the amount for May of the Prior Year (on Line 6) for Account 353 (Column 5) is the sum of the following values:

a) Depreciation Expense for May of the Prior Year (on Line 44, Column 5);
b) Other Transmission Activity for May of the Prior Year (on Line 59, Column 5); and
c) The balances for Transmission Depreciation Reserve for April of the Prior Year (on Line 5, column 5).

2) Amounts on Line 15 derived from Plant Study for previous year Prior Year.
Amounts on Line 16 derived from Plant Study for Prior Year.
3) From 17-Depreciation, Lines 24 to 35.
4) From 6-PlantInService, Lines 93 to 104.
5) Line 13 - Line 1.
6) Line 39.
7) Line 52 - Line 53.
8) Multiply the montly "Total Transmission Allocation Factors" ratios found in Lines 40-51 by the "Other Activity" on Line 54.

Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities

Cells shaded yellow are input cells

1) Summary of Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities

a) End of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities

	Col 1	Col 2	
		Total	
Line	**Account**	**Balance**	**Source**
1	Account 190	$39,126,302	Line 353, Col. 2
2	Account 282	-$1,090,207,015	Line 452, Col. 2
3	Account 283	-$15,708,510	Line 803, Col. 2
4	Net Excess/Deficient Deferred Tax Liability/Asset - 2017 TCAJA	-$582,299,547	FF1 278, see Notes 4 and 5
5	Total Accumulated Deferred Income Taxes	-$1,649,088,770	Sum of Lines 1 to 4
6	and Net Excess Deferred Tax Liabilities		
7	**b) Beginning of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities**		
8		**BOY**	
9		**Balance**	**Source**
10	Total Accumulated Deferred Income Taxes	-$1,550,608,605	Previous Year Informational Filing, Line 5, Col. 2
11			
12	**c) Prorata Average of Beginning and End of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities**		
13		**Average**	
14		**ADIT**	**Source**
15	Prorata Average Balance:	-$1,595,958,946	Line 817, Coumn 8

2) Account 190 Detail

	ACCT 190	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
	Electric:							
100	190.000	Amort of Debt Issuance Cost	$649,241	$506		$648,735		C: Relates to all Regulated Electric Property
101	190.000	Executive Incentive Comp	$3,146,087	$9,014			$3,137,073	C: Relates to employees in all functions
102	190.000	Bond Discount Amort	$771,695	$602		$771,093		C: Relates to all Regulated Electric Property
103	190.000	Executive Incentive Plan	$1,536,403	$4,402			$1,532,001	C: Relates to employees in all functions
104	190.000	Ins - Inj/Damages Prov	$29,451,918	$84,386			$29,367,532	C: Relates to employees in all functions
105	190.000	Accrued Vacation	$11,617,959	$33,288			$11,584,671	C: Relates to employees in all functions
106	190.000	PBOP 401H Amortization	$34,717,749	$99,474			$34,618,275	C: Relates to employees in all functions
107	190.000	EMS	$1,247,125	$973		$1,246,152		C: Relates to all Regulated Electric Property
108	190.000	Amortization of Debt Expense	$955,103	$745		$954,358		C: Relates to all Regulated Electric Property
109	190.000	Decommissioning	$421,953,973	$421,953,973				Relates to Nuclear Decommissioning Costs
110	190.000	Balancing Accounts	-$9,045,539	-$9,045,539				Relates Entirely to CPUC Balancing Account Recovery
111	190.000	CIAC/ITCC	$0	$0				Non-Rate Base FAS 109 Tax - CIAC
112	190.000	Pension & PBOP	$9,082,254	$26,023			$9,056,231	C: Relates to employees in all functions
113	190.000	Property/Non-ISO	$6,708,625	$6,708,625				Non-Rate Base Property
114	190.000	Regulatory Assets/Liab	$9,519,058	$9,519,058				Relates to Nonrecovery Balancing Account
115	190.000	Temp - Other/Non-ISO	$1,027,410,561	$1,027,410,561				Not Component of Rate Base
116	190.000	Net Operating Losses DTA	$172,664,412	$0		$172,664,412		NOL/DTA

Continuation of Account 190 Detail

	ACCT 190	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
	Electric:							
117	…							
								Source
250		Total Electric 190	$1,722,386,624	$1,456,806,092	$0	$176,284,750	$89,295,782	Sum of Above Lines beginning on Line 100

Account 190 Gas and Other Income: (Instructions 1&2)

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
300	190.000	Temp - Other/Non-ISO - Gas	-$910	-$910				Gas Related Costs
301	190.000	Net Operating Losses DTA - Gas	$118,747	$118,747				Gas Related Costs
302	190.000	Balancing Accounts	$2,738,775	$2,738,775				Other Non-ISO Related Costs
303	190.000	Temp - Other/Non-ISO - Other	$1,561,144	$1,561,144				Not Component of Rate Base
304	190.000	Net Operating Losses DTA - Other	-$15,234,903	-$15,234,903				Not Component of Rate Base
305	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
350	Total Account 190 Gas and Other Income	-$10,817,147	-$10,817,147	$0	$0	$0	Sum of Above Lines beginning on Line 300
351	Total Account 190	$1,711,569,477	$1,445,988,945	$0	$176,284,750	$89,295,782	Line 250 + Line 350
352	Allocation Factors (Plant and Wages)				19.148%	6.014%	27-Allocators Lines 22 and 9 respectively.
353	Total Account 190 ADIT (Sum of amounts in Columns 4 to 6)	$39,126,302		$0	$33,755,753	$5,370,549	Line 351 * Line 352 for Cols 5 and 6. Col. 4 100% ISO.
354	FERC Form 1 Account 190	$1,711,569,477	Must match amount on Line 351, Col. 2				FF1 234.18c

3) Account 282 Detail

	ACCT 282	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
400	282.000	Fully Normalized Deferred Tax	-$1,090,207,015		-$1,090,207,015			Property-Related FERC Costs
401	282.000	Property/Non-ISO	-$5,756,860,298	-$5,756,860,298				Property-Related CPUC Costs
402	282.000	Capitalized software	-$25,491,012	-$25,491,012				Property-Related CPUC Costs - Cap Software
403	282.000	Audit Rollforward	-$865,727	-$865,727				Property-Related CPUC Costs - Audit
404	282.000	Property/Non-ISO - Gas	-$936,176	-$936,176				Gas Related Costs
405	282.000	Property/Non-ISO - Other	-$6,492,275	-$6,492,275				Other Non-ISO Related Costs
406	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
450	Total Account 282	-$6,880,852,503	-$5,790,645,488	-$1,090,207,015	$0	$0	Sum of Above Lines beginning on Line 400
451	Allocation Factors (Plant and Wages)				19.148%	6.014%	27-Allocators Lines 22 and 9 respectively.
452	Total Account 282 ADIT (Sum of amounts in Columns 4 to 6)	-$1,090,207,015		-$1,090,207,015	$0	$0	Line 450 * Line 451 for Cols 5 and 6. Col. 4 100% ISO.
453	FERC Form 1 Account 282	$6,880,852,503	Must match amount on Line 450, Col. 2				FF1 275.5k

4) Account 283 Detail

	ACCT 283	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
	Electric:							
500	283.000	Ad Valorem Lien Date Adj-Electric	-$42,051,267			-$42,051,267		Relates to all Regulated Electric Property
501	283.000	Refunding & Retirement of Debt	-$39,655,122	-$30,927		-$39,624,195		C: Relates to all Regulated Electric Property
502	283.000	Health Care - IBNR	-$1,149,642	-3,293.98			-$1,146,348	C: Relates to employees in all functions
503	283.000	Balancing Accounts	-$158,026,051	-$158,026,051				Relates Entirely to CPUC Balancing Account Recovery
504	283.000	Capitalized Software	$0	$0				Property-Related CPUC Costs - Cap Software
505	283.000	Decommissioning	-$422,955,253	-$422,955,253				Relates to Nuclear Decommissioning Costs
506	283.000	Property/Non-ISO	$0	$0				Property-Related CPUC Costs
507	283.000	Regulatory Assets/Liab	$0	$0				Relates to Nonrecovery Balancing Account
508	283.000	Temp - Other/Non-ISO	-$83,907,538	-$83,907,538				Non-Rate Base FAS 109 Tax Flow-Thru

Continuation of Account 283 Detail

	ACCT 283	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
	Electric (continued):							
509	…							
650		Total Electric 283	-$747,744,873	-$664,923,063	$0	-$81,675,462	-$1,146,348	Sum of Above Lines beginning on Line 500

Account 283 Gas and Other:

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	(Instructions 1&2) Col 7
700	283.000	Temp - Other/Non-ISO - Gas	-$61,716	-$61,716				Gas Related Costs
701	283.000	Temp - Other/Non-ISO - Other	-$4,351,620	-$4,351,620				Other Non-ISO Related Costs
702	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
800	Total Account 283 Gas and Other	-$4,413,336	-$4,413,336	$0	$0	$0	Sum of Above Lines beginning on Line 700
801	Total Account 283	-$752,158,209	-$669,336,399	$0	-$81,675,462	-$1,146,348	Line 650 + Line 800
802	Allocation Factors (Plant and Wages)				19.148%	6.014%	27-Allocators Lines 22 and 9 respectively.
803	Total Account 283 ADIT (Sum of amounts in Columns 4 to 6)	-$15,708,510		$0	-$15,639,564	-$68,945	Line 801 * Line 802 for Cols 5 and 6. Col. 4 100% ISO.
804	FERC Form 1 Account 283	$752,158,209	Must match amount on Line 801, Col. 2				FF1 277.19k

5) Tax Normalization Calculation Pursuant to Treas. Reg §1.167(l)-1(h)(6)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
		See Note 1	See Note 2			Col 5 / Tot. Days	= Col 2 * Col 6	See Note 3
	Future Test Period	Mthly Deferred Tax Amount	Deferred Tax Balance	Days in Month	Number of Days Left in Period	Prorata Percentages	Monthly Prorata Amounts	Annual Accumulated Prorata Calculation
805	Beginning Deferred Tax Balance (Line 10, Col. 2)		-$1,550,608,605		365	100.00%		-$1,550,608,605
806	January	-$8,206,680.40	-$1,558,815,286	31	334	91.51%	-$7,509,675	-$1,558,118,280
807	February	-$8,206,680.40	-$1,567,021,966	28	306	83.84%	-$6,880,121	-$1,564,998,401
808	March	-$8,206,680.40	-$1,575,228,646	31	275	75.34%	-$6,183,115	-$1,571,181,516
809	April	-$8,206,680.40	-$1,583,435,327	30	245	67.12%	-$5,508,594	-$1,576,690,110
810	May	-$8,206,680.40	-$1,591,642,007	31	214	58.63%	-$4,811,588	-$1,581,501,698
811	June	-$8,206,680.40	-$1,599,848,688	30	184	50.41%	-$4,137,066	-$1,585,638,764
812	July	-$8,206,680.40	-$1,608,055,368	31	153	41.92%	-$3,440,061	-$1,589,078,825
813	August	-$8,206,680.40	-$1,616,262,048	31	122	33.42%	-$2,743,055	-$1,591,821,880
814	September	-$8,206,680.40	-$1,624,468,729	30	92	25.21%	-$2,068,533	-$1,593,890,413
815	October	-$8,206,680.40	-$1,632,675,409	31	61	16.71%	-$1,371,527	-$1,595,261,940
816	November	-$8,206,680.40	-$1,640,882,090	30	31	8.49%	-$697,006	-$1,595,958,946
817	December	-$8,206,680.40	-$1,649,088,770	31	0	0.00%	$0	-$1,595,958,946
818	Ending Balance (Line 5, Col. 2)		-$1,649,088,770					

Instruction 1: For any "Company Wide" ADIT line item balance (i.e., that include Catalina Gas or Water costs), indicate in Column 7 with a leading "C:".

Instruction 2: For any Company Wide ADIT balance items, include a portion of the total Column 2 balance in Column 3 "Gas, Generation, or Other Related" based on the following percentages.

1) For Line items allocated based on the Wages and Salaries Allocation Factor:

	FERC Form 1 Reference or Instruction	Prior Year Value
A:Total Electric Wages and Salaries	FF1 354.28b	$749,285,680
B:Gas Wages and Salaries	FF1 355.62b	$615,045
C:Water Wages and Salaries	FF1 355.64b	$1,537,997
D:Total Electric, Gas, and Water Wages and Salaries	A+B+C	$751,438,722
E:Labor Percentage "Gas, Generation, or Other"	(B+C) / D	0.2865%

2) For Line items allocated based on the Transmission Plant Allocation Factor or "ISO Only":

	FERC Form 1 Reference or Instruction	Prior Year Value
F:Total Electric Plant In Service	FF1 207.104g	$46,164,121,713
G:Total Gas Plant In Service	FF1 201.8d	$6,268,777
H:Total Water Plant in Service	FF1 201.8e	$29,763,069
I:Total Electric, Gas, and Water Plant In Service	F+G+H	$46,200,153,559
J:Plant Percentage "Gas, Generation, or Other"	(G+H) / I	0.0780%

Instruction 3: Classify any ADIT line items relating to refunding and retirement of debt as Plant related (Column 5).

Notes:

1) The monthly deferred tax amounts are equal to the ending Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities balance minus the beginning Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities balance, divided by 12 months.
2) For January through December = previous month balance plus amount in Column 2.
3) The average Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities Balance is equal to the amount on Line 817, Column 8. Line 805 is equal to Line 10, Column 2. Lines 806 through 817 equal previous amount in Column 8, plus amount in Column 7.
4) The net excess/deficiency is derived from the deficiency arising in Account 190 offset by excesses in Accounts 282 and 283.
5) SCE must submit a Federal Power Act Section 205 filing to obtain Commission approval prior to reflecting in rates any regulatory assets and liabilities arising from future tax changes.

Prior Year CWIP and Forecast Period Incremental CWIP by Project

Prior Year CWIP is the amount of Construction Work In Progress for projects that have received Commission approval to include CWIP in Rate Base.

1) Prior Year CWIP, Total and by Project

Line	Month	Year	Col 1 = Sum of all columns Monthly Total CWIP	Col 2 Tehachapi	Col 3 Devers to Colorado River	Col 4 South of Kramer	Col 5 West of Devers	Col 6 Red Bluff
1	December	2016	$115,749,706	$14,915,548	$0	$4,204,927	$69,685,245	$0
2	January	2017	$117,194,142	$15,082,524	$0	$4,239,931	$70,177,660	$0
3	February	2017	$119,164,541	$15,117,127	$0	$4,296,863	$71,031,101	$0
4	March	2017	$125,730,091	$15,123,625	$0	$4,400,061	$73,723,204	$0
5	April	2017	$95,419,244	$15,192,634	$0	$4,461,541	$75,120,416	$0
6	May	2017	$82,582,163	$149,718	$0	$4,476,504	$77,300,754	$0
7	June	2017	$84,504,679	$149,718	$0	$4,697,238	$78,966,264	$0
8	July	2017	$85,941,140	$149,718	$0	$4,761,048	$80,276,384	$0
9	August	2017	$89,338,929	$150,129	$0	$4,777,853	$83,585,450	$0
10	September	2017	$91,194,895	$150,062	$0	$4,824,268	$85,335,965	$0
11	October	2017	$91,967,696	$150,062	$0	$4,844,918	$86,972,716	$0
12	November	2017	$134,322,419	$150,062	$0	$4,852,268	$91,066,687	$0
13	December	2017	$221,778,480	$150,976	$0	$4,884,728	$98,805,812	$0
14	13 Month Averages:		$111,914,471	$5,894,762	$0	$4,594,011	$80,157,512	$0

Line	Month	Year	Col 7 Whirlwind Substation Expansion	Col 8 Colorado River Substation Expansion	Col 9 Mesa	Col 10 Alberhill	Col 11 ELM Series Caps	Col 12
15	December	2016	$26,943,987	$0	$0	$0	$0	
16	January	2017	$27,694,027	$0	$0	$0	$0	
17	February	2017	$28,719,449	$0	$0	$0	$0	
18	March	2017	$32,483,202	$0	$0	$0	$0	
19	April	2017	$644,653	$0	$0	$0	$0	
20	May	2017	$655,187	$0	$0	$0	$0	
21	June	2017	$691,460	$0	$0	$0	$0	
22	July	2017	$753,990	$0	$0	$0	$0	
23	August	2017	$825,497	$0	$0	$0	$0	
24	September	2017	$884,600	$0	$0	$0	$0	
25	October	2017	$0	$0	$0	$0	$0	
26	November	2017	$0	$0	$38,253,401	$0	$0	
27	December	2017	$0	$0	$46,788,116	$36,155,803	$34,993,045	
28	13 Month Averages:		$9,253,542	$0	$6,541,655	$2,781,216	$2,691,773	---

2) Total Forecast Period CWIP Expenditures (see Note 1)

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
			See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
29	December	2017	---	---	---	---	---	---	$221,778,480	---
30	January	2018	$9,351,204	$701,340	$10,052,544	$5,037,315	$4,098,417	$70,417	$226,723,291	$4,944,811
31	February	2018	$10,204,202	$765,315	$10,969,517	$1,615,948	$0	$121,196	$235,955,664	$14,177,184
32	March	2018	$22,153,491	$1,661,512	$23,815,003	$1,024,177	$0	$76,813	$258,669,677	$36,891,197
33	April	2018	$9,357,335	$701,800	$10,059,135	$116,255	$0	$8,719	$268,603,838	$46,825,358
34	May	2018	$14,954,818	$1,121,611	$16,076,429	$786,000	$0	$58,950	$283,835,317	$62,056,838
35	June	2018	$17,718,219	$1,328,866	$19,047,085	$3,410,370	$2,447,558	$72,211	$299,399,822	$77,621,342
36	July	2018	$12,070,760	$905,307	$12,976,067	$548,326	$0	$41,124	$311,786,439	$90,007,959
37	August	2018	$16,798,571	$1,259,893	$18,058,464	$297,663	$0	$22,325	$329,524,915	$107,746,435
38	September	2018	$13,815,047	$1,036,129	$14,851,175	$349,971	$0	$26,248	$343,999,871	$122,221,392
39	October	2018	$24,263,780	$1,819,783	$26,083,563	$77,673	$0	$5,825	$369,999,936	$148,221,457
40	November	2018	$22,781,801	$1,708,635	$24,490,436	$47,000	$0	$3,525	$394,439,847	$172,661,367
41	December	2018	$27,803,219	$2,085,241	$29,888,461	$20,677,884	$8,513,638	$912,318	$402,738,105	$180,959,625
42	January	2019	$10,509,601	$788,220	$11,297,821	$185,930	$0	$13,945	$413,836,051	$192,057,571
43	February	2019	$18,429,548	$1,382,216	$19,811,764	$204,643	$0	$15,348	$433,427,824	$211,649,344
44	March	2019	$20,210,543	$1,515,791	$21,726,333	$361,034	$0	$27,078	$454,766,046	$232,987,566
45	April	2019	$18,395,093	$1,379,632	$19,774,725	$373,816	$0	$28,036	$474,138,918	$252,360,439
46	May	2019	$19,070,892	$1,430,317	$20,501,209	$400,431	$0	$30,032	$494,209,664	$272,431,185
47	June	2019	$34,328,459	$2,574,634	$36,903,093	$413,213	$0	$30,991	$530,668,553	$308,890,074
48	July	2019	$21,416,333	$1,606,225	$23,022,558	$432,387	$0	$32,429	$553,226,295	$331,447,816
49	August	2019	$22,238,370	$1,667,878	$23,906,247	$14,427,934	$8,470,083	$446,839	$562,257,769	$340,479,290
50	September	2019	$24,775,209	$1,858,141	$26,633,350	$453,078	$0	$33,981	$588,404,060	$366,625,580
51	October	2019	$23,310,193	$2,891,632	$41,446,725	$19,987,218	$9,341,864	$798,402	$609,065,165	$387,286,685
52	November	2019	$28,594,395	$2,488,229	$35,664,615	$16,531,554	$6,140,181	$779,353	$627,418,873	$405,640,393
53	December	2019	$33,982,790	$2,548,709	$36,531,499	$5,786,285	$2,531,642	$244,098	$657,919,989	$436,141,510
54	**13-Month Averages:**									**$301,458,237**

3) Forecast Period CWIP Expenditures by Project (see Note 1)

3a) Project: Tehachapi

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
55	December	2017	---	---	---	---	---	---	$150,976	---
56	January	2018	$426,481	$31,986	$458,467	$191,116	$0	$14,334	$403,994	$253,017
57	February	2018	$659,259	$49,444	$708,703	$891,972	$0	$66,898	$153,827	$2,851
58	March	2018	$589,704	$44,228	$633,932	$588,345	$0	$44,126	$155,288	$4,312
59	April	2018	$82,255	$6,169	$88,424	$80,255	$0	$6,019	$157,438	$6,462
60	May	2018	$788,000	$59,100	$847,100	$786,000	$0	$58,950	$159,588	$8,612
61	June	2018	$703,326	$52,749	$756,075	$862,313	$150,976	$53,350	$0	-$150,976
62	July	2018	$503,326	$37,749	$541,075	$503,326	$0	$37,749	$0	-$150,976
63	August	2018	$252,663	$18,950	$271,613	$252,663	$0	$18,950	$0	-$150,976
64	September	2018	$304,971	$22,873	$327,844	$304,971	$0	$22,873	$0	-$150,976
65	October	2018	$2,000	$150	$2,150	$2,000	$0	$150	$0	-$150,976
66	November	2018	$2,000	$150	$2,150	$2,000	$0	$150	$0	-$150,976
67	December	2018	$2,161,291	$162,097	$2,323,388	$2,161,291	$0	$162,097	$0	-$150,976
68	January	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
69	February	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
70	March	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
71	April	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
72	May	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
73	June	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
74	July	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
75	August	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
76	September	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
77	October	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
78	November	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
79	December	2019	$0	$0	$0	$0	$0	$0	$0	-$150,976
80	**13-Month Averages:**									**-$150,976**

3b) Project: Devers to Colorado River

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
81	December	2017	---	---	---	---	---	---	$0	---
82	January	2018	$0	$0	$0	$0	$0	$0	$0	$0
83	February	2018	$0	$0	$0	$0	$0	$0	$0	$0
84	March	2018	$0	$0	$0	$0	$0	$0	$0	$0
85	April	2018	$0	$0	$0	$0	$0	$0	$0	$0
86	May	2018	$0	$0	$0	$0	$0	$0	$0	$0
87	June	2018	$0	$0	$0	$0	$0	$0	$0	$0
88	July	2018	$0	$0	$0	$0	$0	$0	$0	$0
89	August	2018	$0	$0	$0	$0	$0	$0	$0	$0
90	September	2018	$0	$0	$0	$0	$0	$0	$0	$0
91	October	2018	$0	$0	$0	$0	$0	$0	$0	$0
92	November	2018	$0	$0	$0	$0	$0	$0	$0	$0
93	December	2018	$0	$0	$0	$0	$0	$0	$0	$0
94	January	2019	$0	$0	$0	$0	$0	$0	$0	$0
95	February	2019	$0	$0	$0	$0	$0	$0	$0	$0
96	March	2019	$0	$0	$0	$0	$0	$0	$0	$0
97	April	2019	$0	$0	$0	$0	$0	$0	$0	$0
98	May	2019	$0	$0	$0	$0	$0	$0	$0	$0
99	June	2019	$0	$0	$0	$0	$0	$0	$0	$0
100	July	2019	$0	$0	$0	$0	$0	$0	$0	$0
101	August	2019	$0	$0	$0	$0	$0	$0	$0	$0
102	September	2019	$0	$0	$0	$0	$0	$0	$0	$0
103	October	2019	$0	$0	$0	$0	$0	$0	$0	$0
104	November	2019	$0	$0	$0	$0	$0	$0	$0	$0
105	December	2019	$0	$0	$0	$0	$0	$0	$0	$0
106	13-Month Averages:									**$0**

3c) Project: South of Kramer

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
107	December	2017	---	---	---	---	---	---	$4,884,728	---
108	January	2018	$11,515	$864	$12,379	$0	$0	$0	$4,897,107	$12,379
109	February	2018	$11,776	$883	$12,659	$0	$0	$0	$4,909,766	$25,038
110	March	2018	$11,286	$846	$12,132	$0	$0	$0	$4,921,898	$37,170
111	April	2018	$18,380	$1,379	$19,759	$0	$0	$0	$4,941,657	$56,929
112	May	2018	$18,380	$1,379	$19,759	$0	$0	$0	$4,961,415	$76,687
113	June	2018	$18,380	$1,379	$19,759	$0	$0	$0	$4,981,174	$96,446
114	July	2018	$18,380	$1,379	$19,759	$0	$0	$0	$5,000,932	$116,204
115	August	2018	$18,380	$1,379	$19,759	$0	$0	$0	$5,020,691	$135,963
116	September	2018	$18,380	$1,379	$19,759	$0	$0	$0	$5,040,449	$155,721
117	October	2018	$18,380	$1,379	$19,759	$0	$0	$0	$5,060,208	$175,480
118	November	2018	$18,380	$1,379	$19,759	$0	$0	$0	$5,079,966	$195,238
119	December	2018	$18,383	$1,379	$19,762	$0	$0	$0	$5,099,728	$215,000
120	January	2019	$25,000	$1,875	$26,875	$0	$0	$0	$5,126,603	$241,875
121	February	2019	$25,000	$1,875	$26,875	$0	$0	$0	$5,153,478	$268,750
122	March	2019	$25,000	$1,875	$26,875	$0	$0	$0	$5,180,353	$295,625
123	April	2019	$25,000	$1,875	$26,875	$0	$0	$0	$5,207,228	$322,500
124	May	2019	$25,000	$1,875	$26,875	$0	$0	$0	$5,234,103	$349,375
125	June	2019	$25,000	$1,875	$26,875	$0	$0	$0	$5,260,978	$376,250
126	July	2019	$25,000	$1,875	$26,875	$0	$0	$0	$5,287,853	$403,125
127	August	2019	$125,000	$9,375	$134,375	$0	$0	$0	$5,422,228	$537,500
128	September	2019	$250,000	$18,750	$268,750	$0	$0	$0	$5,690,978	$806,250
129	October	2019	$250,000	$18,750	$268,750	$0	$0	$0	$5,959,728	$1,075,000
130	November	2019	$250,000	$18,750	$268,750	$0	$0	$0	$6,228,478	$1,343,750
131	December	2019	$545,000	$40,875	$585,875	$0	$0	$0	$6,814,353	$1,929,625
132	13-Month Averages:									**$628,048**

3d) Project: West of Devers

Line	Month	Year	Col 1 Forecast Expenditures	Col 2 Corporate Overheads	Col 3 Total CWIP Exp	Col 4 Unloaded Total Plant Adds	Col 5 Prior Period CWIP Closed	Col 6 Over Heads Closed to PIS	Col 7 Forecast Period CWIP	Col 8 Forecast Period Incremental CWIP
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
133	December	2017	---	---	---	---	---	---	$98,805,812	---
134	January	2018	$588,167	$44,113	$632,280	$0	$0	$0	$99,438,091	$632,280
135	February	2018	$2,503,300	$187,748	$2,691,048	$0	$0	$0	$102,129,139	$3,323,327
136	March	2018	$4,798,387	$359,879	$5,158,266	$0	$0	$0	$107,287,405	$8,481,593
137	April	2018	$5,648,177	$423,613	$6,071,790	$0	$0	$0	$113,359,195	$14,553,383
138	May	2018	$5,573,177	$417,988	$5,991,165	$0	$0	$0	$119,350,360	$20,544,549
139	June	2018	$6,499,929	$487,495	$6,987,424	$2,458,051	$2,207,009	$18,828	$123,860,905	$25,055,094
140	July	2018	$5,781,065	$433,580	$6,214,645	$45,000	$0	$3,375	$130,027,175	$31,221,363
141	August	2018	$7,660,609	$574,546	$8,235,155	$45,000	$0	$3,375	$138,213,955	$39,408,143
142	September	2018	$7,537,297	$565,297	$8,102,594	$45,000	$0	$3,375	$146,268,174	$47,462,362
143	October	2018	$18,313,481	$1,373,511	$19,686,992	$75,673	$0	$5,675	$165,873,818	$67,068,006
144	November	2018	$19,079,066	$1,430,930	$20,509,996	$45,000	$0	$3,375	$186,335,438	$87,529,627
145	December	2018	$20,045,130	$1,503,385	$21,548,515	$18,456,121	$8,497,680	$746,883	$188,680,949	$89,875,137
146	January	2019	$4,609,602	$345,720	$4,955,322	$185,000	$0	$13,875	$193,437,396	$94,631,585
147	February	2019	$5,236,167	$392,713	$5,628,880	$190,000	$0	$14,250	$198,862,026	$100,056,214
148	March	2019	$11,290,424	$846,782	$12,137,206	$340,000	$0	$25,500	$210,633,731	$111,827,920
149	April	2019	$12,835,520	$962,664	$13,798,184	$340,000	$0	$25,500	$224,066,415	$125,260,604
150	May	2019	$13,428,006	$1,007,100	$14,435,106	$340,000	$0	$25,500	$238,136,022	$139,330,210
151	June	2019	$14,204,694	$1,065,352	$15,270,046	$340,000	$0	$25,500	$253,040,568	$154,234,756
152	July	2019	$14,472,486	$1,085,436	$15,557,922	$340,000	$0	$25,500	$268,232,990	$169,427,179
153	August	2019	$14,642,486	$1,098,186	$15,740,672	$340,000	$0	$25,500	$283,608,163	$184,802,351
154	September	2019	$15,213,790	$1,141,034	$16,354,824	$340,000	$0	$25,500	$299,597,487	$200,791,675
155	October	2019	$18,580,671	$1,393,550	$19,974,221	$5,706,367	$3,174,605	$189,882	$313,675,460	$214,869,648
156	November	2019	$13,761,026	$1,032,077	$14,793,103	$290,000	$0	$21,750	$328,156,813	$229,351,001
157	December	2019	$14,863,709	$1,114,778	$15,978,487	$290,000	$0	$21,750	$343,823,550	$245,017,738
158	**13-Month Averages:**									**$158,421,232**

3e) Project: Red Bluff

Line	Month	Year	Col 1 Forecast Expenditures	Col 2 Corporate Overheads	Col 3 Total CWIP Exp	Col 4 Unloaded Total Plant Adds	Col 5 Prior Period CWIP Closed	Col 6 Over Heads Closed to PIS	Col 7 Forecast Period CWIP	Col 8 Forecast Period Incremental CWIP
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
159	December	2017	---	---	---	---	---	---	$0	---
160	January	2018	$0	$0	$0	$0	$0	$0	$0	$0
161	February	2018	$0	$0	$0	$0	$0	$0	$0	$0
162	March	2018	$0	$0	$0	$0	$0	$0	$0	$0
163	April	2018	$0	$0	$0	$0	$0	$0	$0	$0
164	May	2018	$0	$0	$0	$0	$0	$0	$0	$0
165	June	2018	$0	$0	$0	$0	$0	$0	$0	$0
166	July	2018	$0	$0	$0	$0	$0	$0	$0	$0
167	August	2018	$0	$0	$0	$0	$0	$0	$0	$0
168	September	2018	$0	$0	$0	$0	$0	$0	$0	$0
169	October	2018	$0	$0	$0	$0	$0	$0	$0	$0
170	November	2018	$0	$0	$0	$0	$0	$0	$0	$0
171	December	2018	$0	$0	$0	$0	$0	$0	$0	$0
172	January	2019	$0	$0	$0	$0	$0	$0	$0	$0
173	February	2019	$0	$0	$0	$0	$0	$0	$0	$0
174	March	2019	$0	$0	$0	$0	$0	$0	$0	$0
175	April	2019	$0	$0	$0	$0	$0	$0	$0	$0
176	May	2019	$0	$0	$0	$0	$0	$0	$0	$0
177	June	2019	$0	$0	$0	$0	$0	$0	$0	$0
178	July	2019	$0	$0	$0	$0	$0	$0	$0	$0
179	August	2019	$0	$0	$0	$0	$0	$0	$0	$0
180	September	2019	$0	$0	$0	$0	$0	$0	$0	$0
181	October	2019	$0	$0	$0	$0	$0	$0	$0	$0
182	November	2019	$0	$0	$0	$0	$0	$0	$0	$0
183	December	2019	$0	$0	$0	$0	$0	$0	$0	$0
184	**13-Month Averages:**									**$0**

3f) Project: Whirlwind Substation Expansion

Line	Month	Year	Col 1 Forecast Expenditures	Col 2 = C1 * 16-Plnt Add Line 74 Corporate Overheads	Col 3 = C1 + C2 Total CWIP Exp	Col 4 Unload Total Plant Adds	Col 5 Prior Period CWIP Closed	Col 6 = (C4 - C5) * 16-Plnt Add Line 74 Over Heads Closed to PIS	Col 7 = Prior Month C7 + C3 - C4 - C6 Forecast Period CWIP	Col 8 = C7 - Dec Prior Year C7 Forecast Period Incremental CWIP
185	December	2017	---	---	---	---	---	---	$0	---
186	January	2018	$10,309	$773	$11,082	$10,309	$0	$773	$0	$0
187	February	2018	$6,204	$465	$6,669	$6,204	$0	$465	$0	$0
188	March	2018	$6,687	$502	$7,189	$6,687	$0	$502	$0	$0
189	April	2018	$0	$0	$0	$0	$0	$0	$0	$0
190	May	2018	$0	$0	$0	$0	$0	$0	$0	$0
191	June	2018	$0	$0	$0	$0	$0	$0	$0	$0
192	July	2018	$0	$0	$0	$0	$0	$0	$0	$0
193	August	2018	$0	$0	$0	$0	$0	$0	$0	$0
194	September	2018	$0	$0	$0	$0	$0	$0	$0	$0
195	October	2018	$0	$0	$0	$0	$0	$0	$0	$0
196	November	2018	$0	$0	$0	$0	$0	$0	$0	$0
197	December	2018	$0	$0	$0	$0	$0	$0	$0	$0
198	January	2019	$0	$0	$0	$0	$0	$0	$0	$0
199	February	2019	$0	$0	$0	$0	$0	$0	$0	$0
200	March	2019	$0	$0	$0	$0	$0	$0	$0	$0
201	April	2019	$0	$0	$0	$0	$0	$0	$0	$0
202	May	2019	$0	$0	$0	$0	$0	$0	$0	$0
203	June	2019	$0	$0	$0	$0	$0	$0	$0	$0
204	July	2019	$0	$0	$0	$0	$0	$0	$0	$0
205	August	2019	$0	$0	$0	$0	$0	$0	$0	$0
206	September	2019	$0	$0	$0	$0	$0	$0	$0	$0
207	October	2019	$0	$0	$0	$0	$0	$0	$0	$0
208	November	2019	$0	$0	$0	$0	$0	$0	$0	$0
209	December	2019	$0	$0	$0	$0	$0	$0	$0	$0
210	**13-Month Averages:**									**$0**

3g) Project: Colorado River Substation Expansion

Line	Month	Year	Col 1 Forecast Expenditures	Col 2 = C1 * 16-Plnt Add Line 74 Corporate Overheads	Col 3 = C1 + C2 Total CWIP Exp	Col 4 Unloaded Total Plant Adds	Col 5 Prior Period CWIP Closed	Col 6 = (C4 - C5) * 16-Plnt Add Line 74 Over Heads Closed to PIS	Col 7 = Prior Month C7 + C3 - C4 - C6 Forecast Period CWIP	Col 8 = C7 - Dec Prior Year C7 Forecast Period Incremental CWIP
211	December	2017	---	---	---	---	---	---	$0	---
212	January	2018	$728	$55	$783	$728	$0	$55	$0	$0
213	February	2018	$1,158	$87	$1,245	$1,158	$0	$87	$0	$0
214	March	2018	$780	$59	$839	$780	$0	$59	$0	$0
215	April	2018	$0	$0	$0	$0	$0	$0	$0	$0
216	May	2018	$0	$0	$0	$0	$0	$0	$0	$0
217	June	2018	$334	$25	$359	$334	$0	$25	$0	$0
218	July	2018	$0	$0	$0	$0	$0	$0	$0	$0
219	August	2018	$0	$0	$0	$0	$0	$0	$0	$0
220	September	2018	$0	$0	$0	$0	$0	$0	$0	$0
221	October	2018	$0	$0	$0	$0	$0	$0	$0	$0
222	November	2018	$0	$0	$0	$0	$0	$0	$0	$0
223	December	2018	$0	$0	$0	$0	$0	$0	$0	$0
224	January	2019	$0	$0	$0	$0	$0	$0	$0	$0
225	February	2019	$0	$0	$0	$0	$0	$0	$0	$0
226	March	2019	$0	$0	$0	$0	$0	$0	$0	$0
227	April	2019	$0	$0	$0	$0	$0	$0	$0	$0
228	May	2019	$0	$0	$0	$0	$0	$0	$0	$0
229	June	2019	$0	$0	$0	$0	$0	$0	$0	$0
230	July	2019	$0	$0	$0	$0	$0	$0	$0	$0
231	August	2019	$0	$0	$0	$0	$0	$0	$0	$0
232	September	2019	$0	$0	$0	$0	$0	$0	$0	$0
233	October	2019	$0	$0	$0	$0	$0	$0	$0	$0
234	November	2019	$0	$0	$0	$0	$0	$0	$0	$0
235	December	2019	$0	$0	$0	$0	$0	$0	$0	$0
236	**13-Month Averages:**									**$0**

3h) Project: Mesa

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
237	December	2017	---	---	---	---	---	---	$46,788,116	---
238	January	2018	$6,150,625	$461,297	$6,611,922	$4,835,162	$4,098,417	$55,256	$48,509,620	$1,721,504
239	February	2018	$6,764,842	$507,363	$7,272,205	$716,614	$0	$53,746	$55,011,464	$8,223,348
240	March	2018	$6,728,747	$504,656	$7,233,403	$428,365	$0	$32,127	$61,784,375	$14,996,259
241	April	2018	$2,637,958	$197,847	$2,835,805	$36,000	$0	$2,700	$64,581,480	$17,793,364
242	May	2018	$7,602,991	$570,224	$8,173,216	$0	$0	$0	$72,754,696	$25,966,580
243	June	2018	$9,514,013	$713,551	$10,227,564	$0	$0	$0	$82,982,260	$36,194,144
244	July	2018	$4,760,538	$357,040	$5,117,579	$0	$0	$0	$88,099,839	$41,311,723
245	August	2018	$7,813,915	$586,044	$8,399,959	$0	$0	$0	$96,499,797	$49,711,681
246	September	2018	$4,860,922	$364,569	$5,225,491	$0	$0	$0	$101,725,289	$54,937,173
247	October	2018	$5,232,286	$392,421	$5,624,708	$0	$0	$0	$107,349,996	$60,561,880
248	November	2018	$3,062,453	$229,684	$3,292,137	$0	$0	$0	$110,642,133	$63,854,017
249	December	2018	$4,668,878	$350,166	$5,019,044	$23,755	$0	$1,782	$115,635,641	$68,847,525
250	January	2019	$5,133,736	$385,030	$5,518,766	$0	$0	$0	$121,154,407	$74,366,291
251	February	2019	$11,785,380	$883,903	$12,669,283	$0	$0	$0	$133,823,690	$87,035,574
252	March	2019	$7,424,715	$556,854	$7,981,568	$0	$0	$0	$141,805,258	$95,017,142
253	April	2019	$4,022,697	$301,702	$4,324,399	$0	$0	$0	$146,129,657	$99,341,541
254	May	2019	$3,957,356	$296,802	$4,254,158	$0	$0	$0	$150,383,815	$103,595,699
255	June	2019	$4,386,911	$329,018	$4,715,929	$0	$0	$0	$155,099,744	$108,311,628
256	July	2019	$5,763,632	$432,272	$6,195,905	$0	$0	$0	$161,295,649	$114,507,533
257	August	2019	$6,352,933	$476,470	$6,829,403	$0	$0	$0	$168,125,052	$121,336,936
258	September	2019	$8,352,169	$626,413	$8,978,581	$0	$0	$0	$177,103,633	$130,315,517
259	October	2019	$3,995,870	$299,690	$4,295,560	$0	$0	$0	$181,399,193	$134,611,077
260	November	2019	$14,262,524	$1,069,689	$15,332,214	$0	$0	$0	$196,731,407	$149,943,291
261	December	2019	$9,312,568	$698,443	$10,011,010	$4,179,168	$2,531,642	$123,564	$202,439,684	$155,651,568
262	**13-Month Averages:**									**$110,990,871**

3i) Project: Alberhill

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
263	December	2017	---	---	---	---	---	---	$36,155,803	---
264	January	2018	$15,725	$1,179	$16,904	$0	$0	$0	$36,172,707	$16,904
265	February	2018	$39,608	$2,971	$42,579	$0	$0	$0	$36,215,286	$59,483
266	March	2018	$43,160	$3,237	$46,397	$0	$0	$0	$36,261,683	$105,880
267	April	2018	$116,635	$8,748	$125,383	$0	$0	$0	$36,387,065	$231,262
268	May	2018	$89,340	$6,700	$96,040	$0	$0	$0	$36,483,105	$327,303
269	June	2018	$86,306	$6,473	$92,779	$89,672	$89,573	$7	$36,486,206	$330,403
270	July	2018	$126,591	$9,494	$136,085	$0	$0	$0	$36,622,291	$466,488
271	August	2018	$170,144	$12,761	$182,905	$0	$0	$0	$36,805,196	$649,393
272	September	2018	$147,617	$11,071	$158,688	$0	$0	$0	$36,963,884	$808,081
273	October	2018	$98,843	$7,413	$106,256	$0	$0	$0	$37,070,140	$914,337
274	November	2018	$315,182	$23,639	$338,821	$0	$0	$0	$37,408,960	$1,253,157
275	December	2018	$63,376	$4,753	$68,129	$0	$0	$0	$37,477,089	$1,321,286
276	January	2019	$273,333	$20,500	$293,833	$0	$0	$0	$37,770,922	$1,615,119
277	February	2019	$108,141	$8,111	$116,252	$12,783	$0	$959	$37,873,432	$1,717,630
278	March	2019	$189,544	$14,216	$203,760	$19,174	$0	$1,438	$38,056,580	$1,900,777
279	April	2019	$243,017	$18,226	$261,243	$31,956	$0	$2,397	$38,283,470	$2,127,667
280	May	2019	$323,230	$24,242	$347,472	$51,131	$0	$3,835	$38,575,976	$2,420,174
281	June	2019	$376,704	$28,253	$404,957	$63,913	$0	$4,793	$38,912,227	$2,756,424
282	July	2019	$456,915	$34,269	$491,183	$83,087	$0	$6,232	$39,314,092	$3,158,289
283	August	2019	$483,650	$36,274	$519,924	$89,478	$0	$6,711	$39,737,827	$3,582,024
284	September	2019	$483,650	$36,274	$519,924	$89,478	$0	$6,711	$40,161,562	$4,005,759
285	October	2019	$483,652	$36,274	$519,926	$89,478	$0	$6,711	$40,585,298	$4,429,495
286	November	2019	$320,845	$24,063	$344,908	$76,696	$0	$5,752	$40,847,758	$4,691,956
287	December	2019	$4,917,683	$368,826	$5,286,510	$31,956	$0	$2,397	$46,099,915	$9,944,112
288	**13-Month Averages:**									**$3,359,286**

3j) Project: ELM Series Capacitors

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
289	December	2017	---	---	---	---	---	---	$34,993,045	---
290	January	2018	$2,147,654	$161,074	$2,308,728	$0	$0	$0	$37,301,773	$2,308,728
291	February	2018	$218,055	$16,354	$234,409	$0	$0	$0	$37,536,182	$2,543,137
292	March	2018	$9,974,740	$748,106	$10,722,846	$0	$0	$0	$48,259,028	$13,265,983
293	April	2018	$853,930	$64,045	$917,975	$0	$0	$0	$49,177,003	$14,183,958
294	May	2018	$882,930	$66,220	$949,150	$0	$0	$0	$50,126,153	$15,133,108
295	June	2018	$895,930	$67,195	$963,125	$0	$0	$0	$51,089,277	$16,096,232
296	July	2018	$880,860	$66,065	$946,925	$0	$0	$0	$52,036,202	$17,043,157
297	August	2018	$882,860	$66,215	$949,075	$0	$0	$0	$52,985,276	$17,992,231
298	September	2018	$945,860	$70,940	$1,016,800	$0	$0	$0	$54,002,076	$19,009,031
299	October	2018	$598,790	$44,909	$643,699	$0	$0	$0	$54,645,775	$19,652,730
300	November	2018	$304,720	$22,854	$327,574	$0	$0	$0	$54,973,349	$19,980,304
301	December	2018	$846,161	$63,462	$909,623	$36,717	$15,958	$1,557	$55,844,698	$20,851,653
302	January	2019	$467,930	$35,095	$503,025	$930	$0	$70	$56,346,723	$21,353,678
303	February	2019	$1,274,860	$95,615	$1,370,475	$1,860	$0	$140	$57,715,198	$22,722,153
304	March	2019	$1,280,860	$96,065	$1,376,925	$1,860	$0	$140	$59,090,123	$24,097,078
305	April	2019	$1,268,860	$95,165	$1,364,025	$1,860	$0	$140	$60,452,148	$25,459,103
306	May	2019	$1,337,300	$100,298	$1,437,598	$9,300	$0	$698	$61,879,748	$26,886,703
307	June	2019	$15,335,150	$1,150,136	$16,485,286	$9,300	$0	$698	$78,355,037	$43,361,992
308	July	2019	$698,300	$52,373	$750,673	$9,300	$0	$698	$79,095,712	$44,102,667
309	August	2019	$634,300	$47,573	$681,873	$13,998,456	$8,470,083	$414,628	$65,364,500	$30,371,455
310	September	2019	$475,600	$35,670	$511,270	$23,600	$0	$1,770	$65,850,400	$30,857,355
311	October	2019	$15,244,900	$1,143,368	$16,388,268	$14,191,373	$6,167,259	$601,809	$67,445,486	$32,452,441
312	November	2019	$4,581,991	$343,649	$4,925,640	$16,164,858	$6,140,181	$751,851	$55,454,417	$20,461,372
313	December	2019	$4,343,830	$325,787	$4,669,617	$1,285,160	$0	$96,387	$58,742,488	$23,749,443
314	**13-Month Averages:**									**$28,209,776**

3k) Project: add additional projects below this line (See Instruction 3)

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
315	December	2017	---	---	---	---	---	---	$0	---
316	January	2018		$0	$0			$0	$0	$0
317	February	2018		$0	$0			$0	$0	$0
318	March	2018		$0	$0			$0	$0	$0
319	April	2018		$0	$0			$0	$0	$0
320	May	2018		$0	$0			$0	$0	$0
321	June	2018		$0	$0			$0	$0	$0
322	July	2018		$0	$0			$0	$0	$0
323	August	2018		$0	$0			$0	$0	$0
324	September	2018		$0	$0			$0	$0	$0
325	October	2018		$0	$0			$0	$0	$0
326	November	2018		$0	$0			$0	$0	$0
327	December	2018		$0	$0			$0	$0	$0
328	January	2019		$0	$0			$0	$0	$0
329	February	2019		$0	$0			$0	$0	$0
330	March	2019		$0	$0			$0	$0	$0
331	April	2019		$0	$0			$0	$0	$0
332	May	2019		$0	$0			$0	$0	$0
333	June	2019		$0	$0			$0	$0	$0
334	July	2019		$0	$0			$0	$0	$0
335	August	2019		$0	$0			$0	$0	$0
336	September	2019		$0	$0			$0	$0	$0
337	October	2019		$0	$0			$0	$0	$0
338	November	2019		$0	$0			$0	$0	$0
339	December	2019		$0	$0			$0	$0	$0
340	**13-Month Averages:**									**$0**

Notes:
1) Forecast Period is the calendar year two years after the Prior Year (i.e., PY+2).
2) Sum of project specific values from lines 55-79, 81-105, 107-131, 133-157, 159-183, 185-209, 211-235, 237-261, 263-287, 289-313,…

Instructions:
1) Enter recorded amounts of CWIP during Prior Year on Lines 1-13, 15-27 (including December of year previous to Prior Year).
2) Enter forecast project specific values on lines 55-79, 81-105, 107-131, 133-157, 159-183, 185-209, 211-235, 237-261, 263-287, 289-313,...
3) If Commission approval is granted to include CWIP in Rate Base for additional projects, include additional tables for each of those additional projects.

TRANSMISSION PLANT HELD FOR FUTURE USE

Inputs are shaded yellow

Transmission Plant Held for Future Use shall be amounts of Electric Plant Held for Future Use (account 105) intended to be placed under the Operational Control of the ISO, plus an allocated amount of any General Electric Plant Held for Future Use, with the allocation factor being the Transmission Wages and Salaries AF.

Line		Beginning of Year Balance	End of Year Balance	Source
1	Total Electric PHFU	$16,261,841	$15,781,292	FF1 page 214.47d

Plant intended to be placed under the Operational Control of the ISO:

	Col 1 Description	Col 2 Type of Plant	Col 3 Beginning of Year Balance	Col 4 End of Year Balance	Col 5 Source
2a	Alberhill	Sub	$9,942,155	$9,942,155	SCE records
2b					
2c					
2d					
2e					
2f					
2g					
2h					
	...				
3		Total:	$9,942,155	$9,942,155	Sum of above lines

		Beginning of Year Balance	End of Year Balance	Source
4	General Plant Held for Future Use	$0	$0	FF1 page 214
5	Wages and Salaries AF:	6.014%	6.014%	27-Allocators, L 9
6	Portion for Transmission PHFU:	$0	$0	L 4 * L 5

All other Electric Plant Held for Future Use not intended to be placed under the Operational Control of the ISO:

		Beginning of Year Balance	End of Year Balance	Source
7		$6,319,686	$5,839,137	Note 1

	Transmission PHFU:	Beginning of Year Balance	End of Year Balance	Source
8		$9,942,155	$9,942,155	L 3 + L 6
9	Average of BOY and EOY Transmission PHFU:	$9,942,155		Sum of Line 8 / 2

Calculation of Gain or Loss on Transmission Plant Held for Future Use -- Land

			Source
10	Gain or Loss on Transmission Plant Held for Future Use --- Land	$0	SCE Records

Instructions:
1) For any Electric Plant Held for Future Use intended to be placed under the Operational Control of the ISO, list on lines 2a, 2b, etc. Provide description in Column 1. Note type of plant (land or other) in Column 2. Under "Source" (Column 5), state the line number on FERC Form 1 page 214 from which the amount is derived. BOY amount will be EOY value from previous year FERC Form 1, EOY amount will be in current year FF1.
2) For any Electric Plant Held for Future Use classified as General note amount on Line 4.
3) Add additional lines 2 i, j, k, etc. as necessary to include additional projects intended to be placed under the Operational Control of the ISO.
4) Gains and Losses on Transmission Plant Held for Future Use - Land is treated in accordance with Commission policy. Any gain or loss on non-land portions of Transmission Plant Held for Future Use is not included.

Notes:
1) Amount of Line 1 not intended to be placed under the Operational Control of the ISO.

Determination of amount of Abandoned Plant and Abandoned Plant Amortization Expense

Input data is shaded yellow

Initially Abandoned Plant Amortization Expense and Abandoned Plant are both zero.

Upon Commission approval of recovery of abandoned plant costs for a specific project or projects, SCE will complete this worksheet in accordance with that Order.

	Project	Commission Order
Orders Providing for Abandoned Plant Cost Recovery:		
	…	…

Abandoned Plant for each project represents the amount of costs that the Order approves for inclusion in Rate Base.

Abandoned Plant Amortization Expense for each project represents the annual amortization of abandoned costs that the Order approves as an annual expense.

Line		Amount for Prior Year	Note:
1	Abandoned Plant Amortization Expense:	$0	Sum of projects below for PY.
2	Abandoned Plant (BOY):	$0	Sum of projects below for PY.
3	Abandoned Plant (EOY):	$0	Sum of projects below for PY.
4	Abandoned Plant (BOY/EOY Average):	$0	Average of Lines 2 and 3.
5	HV Abandoned Plant (BOY):	$0	Sum of projects below for PY.

6 **First Project:** Fill in Name **2nd Project:** Fill in Name

	Year	EOY Abandoned Plant	EOY HV Abandoned Plant (Note 1)	Abandoned Plant Amort. Expense	EOY Abandoned Plant	EOY HV Abandoned Plant (Note 1)	Abandoned Plant Amort. Expense
7	2015						
8	2016						
9	2017						
10	2018						
11	2019						
12	2020						
13	2021						
14	2022						
15	2023						
16	2024						
17	2025						
18	…						

Notes:
1) "EOY HV Abandoned Plant" is amount of "EOY Abandoned Plant" that would have been High Voltage (>= 200 kV).

Instructions:
1) Upon Commission approval of recovery of abandoned plant costs for a project:
   a) Fill in the name the project in order (First Project, Second Project, etc.).
   b) Fill in the table with annual End of Year ("EOY") Abandoned Plant, EOY HV Abandoned Plant, and Abandoned Plant Amortization Expense amounts in Accordance with the Order.
   If table can not be filled out completely, fill out at least through the Prior Year at issue.
   c) Sum project-specific amounts for each project and enter in lines 1, 2, and 3 for the Prior Year at issue.
   (BOY value is EOY value from previous year)
2) Add additional projects if necessary in same format.
3) Add additional years past 2025 if necessary.

Calculation of Components of Working Capital

Inputs are shaded yellow

1) Calculation of Materials and Supplies

Materials and Supplies is the amount of total Account 154 Materials and Supplies times the Transmission Wages and Salaries AF

Line	Month	Year	Data Source	Total Materials and Supplies Balances	Notes
1	December	2016	FF1 227.12b	$237,798,844	Beginning of year ("BOY") amount
2	January	2017	SCE Records	$236,701,406	
3	February	2017	SCE Records	$235,215,054	
4	March	2017	SCE Records	$234,227,486	
5	April	2017	SCE Records	$229,290,189	
6	May	2017	SCE Records	$227,387,009	
7	June	2017	SCE Records	$229,834,302	
8	July	2017	SCE Records	$231,240,887	
9	August	2017	SCE Records	$229,531,353	
10	September	2017	SCE Records	$226,308,483	
11	October	2017	SCE Records	$229,185,237	
12	November	2017	SCE Records	$230,757,406	
13	December	2017	FF1 227.12c	$238,006,741	End of Year ("EOY") amount
14		13-Month Average Value Account 154:		$231,960,338	(Sum Line 1 to Line 13) / 13
15		Transmission Wages and Salaries AF:		6.014%	27-Allocators, Line 9
16	**Materials and Supplies**		EOY Value:	$14,314,526	Line 13 * Line 15
17			13-Month Average Value:	$13,950,875	Line 14 * Line 15

2) Calculation of Prepayments

Prepayments is an allocated portion of Total Prepayments based on the Transmission Wages and Salaries Allocation Factor.

Line	Month	Year	Data Source	Total Prepayments Balances	Notes
18	December	2016	Note 1, c	$99,369,093	See Note 1, c
19	January	2017	SCE Records	$120,656,391	
20	February	2017	SCE Records	$110,804,401	
21	March	2017	SCE Records	$169,364,348	
22	April	2017	SCE Records	$230,958,817	
23	May	2017	SCE Records	$190,396,526	
24	June	2017	SCE Records	$135,529,209	
25	July	2017	SCE Records	$144,680,436	
26	August	2017	SCE Records	$136,252,209	
27	September	2017	SCE Records	$306,743,337	
28	October	2017	SCE Records	$290,763,947	
29	November	2017	SCE Records	$295,532,251	
30	December	2017	Note 1, f	$227,852,643	See Note 1, f
	a) 13-Month Average Calculation				
31			13-Month Average Value:	$189,146,431	(Sum Line 18 to Line 30) / 13
32			Transmission Wages and Salaries AF:	6.0143%	27-Allocators, Line 9
33			Prepayments:	$11,375,902	Line 31 * Line 32
	b) EOY calculation				
34			EOY Value:	$227,852,643	Line 30
35			Transmission Wages and Salaries AF:	6.0143%	27-Allocators, Line 9
36			Prepayments:	$13,703,824	Line 34 * Line 35

Notes:

1) Remove any amounts related to years prior to 2012 on b and e below.

	Beginning of Year Amount	Prepayments Balances	Source
a	FERC Form 1 Acct. 165 Recorded Amount:	$114,171,737	FF1 111.57d
b	Prior Period Adjustment:	$14,802,644	Note 1
c	BOY Prepayments Amount:	$99,369,093	a - b

	End of Year Amount	Prepayments Balances	Source
d	FERC Form 1 Acct. 165 Recorded Amount:	$227,852,643	FF1 111.57c
e	Prior Period Adjustment:	$0	Note 1
f	EOY Prepayments Amount:	$227,852,643	d - e

Plant Balances For Incentive Projects Receiving either ROE Incentives ("Transmission Incentive Plant") or CWIP ("CWIP Plant")

Input data is shaded yellow

A) Summary of Incentive Project plant balances receiving ROE incentives ("Transmission Incentive Plant") and/or CWIP ("CWIP Plant") and calculation of balances needed to determine the following:

1) Rate Base in Prior Year
2) Prior Year Incentive Rate Base - End of Year
3) Prior Year Incentive Rate Base - 13-Month Average

Transmission Incentive Project plant balances and CWIP Plant may affect the following:

a) CWIP Plant during the Prior Year is included in Rate Base (used in Prior Year TRR and True Up TRR).
b) Forecast Period Incremental CWIP contributes to Incremental Forecast Period TRR
c) CWIP Plant receiving an ROE adder contributes to Prior Year Incentive Rate Base - EOY, or Prior Year Incentive Rate Base - 13 Month Average as appropriate.
d) "TIP Net Plant In Service" at EOY Prior Year is used to calculate the PY Incentive Rate Base (on EOY basis).
e) "TIP Net Plant In Service" in PY is used to calculate the Prior Year Incentive Rate Base (on 13-month average basis).

1) Summary of CWIP Plant in Prior Year and Forecast Period

Line	Incentive Project	Col 1 Prior Year End-of-Year CWIP Plant Amount	Col 2 Prior Year 13-Month Average CWIP Plant Amount	Col 3 Forecast Period Incremental CWIP 13-Month Avg. Amount	Notes:
1	1) Tehachapi	$150,976	$5,894,762	-$150,976	10-CWIP Lines 13, 14, and 80
2	2) Devers-Colorado River	$0	$0	$0	10-CWIP Lines 13, 14, and 106
3	3) South of Kramer	$4,884,728	$4,594,011	$628,048	10-CWIP Lines 13, 14, and 132
4	4) West of Devers	$98,805,812	$80,157,512	$158,421,232	10-CWIP Lines 13, 14, and 158
5	5) Red Bluff	$0	$0	$0	10-CWIP Lines 13, 14, and 184
6	6) Whirlwind Substation Exp.	$0	$9,253,542	$0	10-CWIP Lines 27, 28, and 210
7	7) Colorado River Sub. Exp.	$0	$0	$0	10-CWIP Lines 27, 28, and 236
8	8) Mesa	$46,788,116	$6,541,655	$110,990,871	10-CWIP Lines 27, 28, and 262
9	9) Alberhill	$36,155,803	$2,781,216	$3,359,286	10-CWIP Lines 27, 28, and 288
10	10) ELM Series Caps	$34,993,045	$2,691,773	$28,209,776	10-CWIP Lines 27, 28, and 314
11	…	---	---	---	…
12	Totals:	$221,778,480	$111,914,471	$301,458,237	

2) Summary of Prior Year Incentive Rate Base amounts (EOY Values)

Line		Col 1 = C2 + C3 Prior Year Incentive Rate Base	Col 2 EOY CWIP Portion	Col 3 EOY TIP Net Plant In Service	Notes:
13	1) Rancho Vista	$150,232,043	$0	$150,232,043	Line 37, C4
14	2) Tehachapi	$2,728,701,253	$150,976	$2,728,550,276	Line 1, C1, and Line 37, C2
15	3) Devers-Colorado River	$687,752,340	$0	$687,752,340	Line 2, C1, and Line 37, C3
16	…	---	---	---	…
17					
18	Total PY Incentive Net Plant:	$3,566,685,636			End of Year

3) Summary of Prior Year Incentive Rate Base amounts (13-Month Average values)

Line	Incentive Project	Col 1 = C2 + C3 Prior Year Incentive Rate Base	Col 2 13-Month Avg. CWIP Portion	Col 3 13-Month Avg. TIP Net Plant In Service Portion	Notes:
19	1) Rancho Vista	$152,604,254	$0	$152,604,254	Line 38, C4
20	2) Tehachapi	$2,756,592,235	$5,894,762	$2,750,697,473	Line 1, C2, and Line 38, C2
21	3) Devers-Colorado R	$697,660,501	$0	$697,660,501	Line 2, C2, and Line 38, C3
22	…	---	---	---	…
23					
24	Total PY Incentive Net Plant:	$3,606,856,990			13 Month Average

4) Prior Year TIP Net Plant In Service

	Prior Year Month	Year	Col 1 Total TIP Net Plant In Service	Col 2 L 53 to L 65, C3 Tehachapi	Col 3 L 79 to L 91, C3 Devers to Colorado River	Col 4 L 66 to L 78, C3 Rancho Vista	Col 5	Notes
25	December	2016	$3,623,644,583	$2,761,096,354	$707,569,233	$154,978,996	---	←December of
26	January	2017	$3,615,880,495	$2,755,369,096	$705,927,339	$154,584,059	---	year previous
27	February	2017	$3,614,032,508	$2,755,580,398	$704,262,987	$154,189,123	---	to Prior Year
28	March	2017	$3,610,703,590	$2,754,293,881	$702,621,120	$153,788,590	---	
29	April	2017	$3,603,732,187	$2,749,366,950	$700,971,573	$153,393,664	---	
30	May	2017	$3,617,080,147	$2,764,751,667	$699,329,740	$152,998,739	---	
31	June	2017	$3,611,530,160	$2,761,235,317	$697,691,029	$152,603,814	---	
32	July	2017	$3,604,314,877	$2,756,061,325	$696,044,662	$152,208,889	---	
33	August	2017	$3,597,373,681	$2,751,250,377	$694,311,578	$151,811,726	---	
34	September	2017	$3,590,313,710	$2,746,221,604	$692,675,301	$151,416,805	---	
35	October	2017	$3,584,010,799	$2,741,953,296	$691,035,618	$151,021,884	---	
36	November	2017	$3,573,357,571	$2,733,336,611	$689,393,997	$150,626,964	---	
37	December	2017	$3,566,534,659	$2,728,550,276	$687,752,340	$150,232,043	---	
38		13 Month Averages:	$3,600,962,228	$2,750,697,473	$697,660,501	$152,604,254		

5) Total Transmission Activity for Incentive Projects

	Prior Year Month	Year	Col 1 Total Transmission Activity for Incentive Projects	Col 2 Account 360-362 Activity	Col 3 = C1 - C2 Account 350-359 Activity for Incentive Projects	Source
39	December	2016	$0	$0	$0	C1: Sum of below projects
40	January	2017	$637,077	$0	$637,077	for each month
41	February	2017	$6,682,963	$0	$6,682,963	
42	March	2017	$5,178,669	$0	$5,178,669	
43	April	2017	$34,083,658	$0	$34,083,658	
44	May	2017	$21,945,099	$0	$21,945,099	
45	June	2017	$2,931,169	$0	$2,931,169	
46	July	2017	$1,250,328	$0	$1,250,328	
47	August	2017	$1,528,249	$0	$1,528,249	
48	September	2017	$1,390,223	$0	$1,390,223	
49	October	2017	$2,916,673	$0	$2,916,673	
50	November	2017	-$517,602	$0	-$517,602	
51	December	2017	$1,650,013	$0	$1,650,013	
52	Total		$79,676,521	$0	$79,676,521	

6) Calculation of Prior Year Net Plant in Service amounts for each Incentive Project

a) Tehachapi

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
53	December	2016	$2,998,641,930	$237,545,576	$2,761,096,354	$0
54	January	2017	$2,999,220,787	$243,851,690	$2,755,369,096	$578,857
55	February	2017	$3,005,739,539	$250,159,141	$2,755,580,398	$6,518,753
56	March	2017	$3,010,773,105	$256,479,225	$2,754,293,881	$5,033,566
57	April	2017	$3,012,180,175	$262,813,225	$2,749,366,950	$1,407,069
58	May	2017	$3,033,901,664	$269,149,997	$2,764,751,667	$21,721,489
59	June	2017	$3,036,761,062	$275,525,745	$2,761,235,317	$2,859,397
60	July	2017	$3,037,969,275	$281,907,950	$2,756,061,325	$1,208,213
61	August	2017	$3,039,542,946	$288,292,570	$2,751,250,377	$1,573,672
62	September	2017	$3,040,901,421	$294,679,817	$2,746,221,604	$1,358,475
63	October	2017	$3,043,025,002	$301,071,706	$2,741,953,296	$2,123,581
64	November	2017	$3,040,804,627	$307,468,016	$2,733,336,611	-$2,220,375
65	December	2017	$3,042,408,308	$313,858,031	$2,728,550,276	$1,603,681

	b) Rancho Vista		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
66	December	2016	$191,508,708	$36,529,712	$154,978,996	$0
67	January	2017	$191,508,708	$36,924,649	$154,584,059	$0
68	February	2017	$191,508,708	$37,319,585	$154,189,123	$0
69	March	2017	$191,503,112	$37,714,522	$153,788,590	-$5,596
70	April	2017	$191,503,112	$38,109,447	$153,393,664	$0
71	May	2017	$191,503,112	$38,504,373	$152,998,739	$0
72	June	2017	$191,503,112	$38,899,298	$152,603,814	$0
73	July	2017	$191,503,112	$39,294,223	$152,208,889	$0
74	August	2017	$191,500,874	$39,689,148	$151,811,726	-$2,238
75	September	2017	$191,500,874	$40,084,069	$151,416,805	$0
76	October	2017	$191,500,874	$40,478,989	$151,021,884	$0
77	November	2017	$191,500,874	$40,873,910	$150,626,964	$0
78	December	2017	$191,500,874	$41,268,831	$150,232,043	$0

	c) Devers to Colorado River		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
79	December	2016	$773,686,037	$66,116,803	$707,569,233	$0
80	January	2017	$773,686,037	$67,758,698	$705,927,339	$0
81	February	2017	$773,663,579	$69,400,592	$704,262,987	-$22,458
82	March	2017	$773,663,560	$71,042,441	$702,621,120	-$19
83	April	2017	$773,655,861	$72,684,289	$700,971,573	-$7,699
84	May	2017	$773,655,861	$74,326,121	$699,329,740	$0
85	June	2017	$773,658,982	$75,967,954	$697,691,029	$3,121
86	July	2017	$773,654,455	$77,609,792	$696,044,662	-$4,528
87	August	2017	$773,563,195	$79,251,617	$694,311,578	-$91,259
88	September	2017	$773,568,549	$80,893,248	$692,675,301	$5,354
89	October	2017	$773,570,518	$82,534,900	$691,035,618	$1,969
90	November	2017	$773,570,554	$84,176,557	$689,393,997	$35
91	December	2017	$773,570,554	$85,818,214	$687,752,340	$0

	d) South of Kramer		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
92	December	2016	$0	$0	$0	$0
93	January	2017	$0	$0	$0	$0
94	February	2017	$0	$0	$0	$0
95	March	2017	$0	$0	$0	$0
96	April	2017	$0	$0	$0	$0
97	May	2017	$0	$0	$0	$0
98	June	2017	$0	$0	$0	$0
99	July	2017	$0	$0	$0	$0
100	August	2017	$0	$0	$0	$0
101	September	2017	$0	$0	$0	$0
102	October	2017	$0	$0	$0	$0
103	November	2017	$0	$0	$0	$0
104	December	2017	$0	$0	$0	$0

e) West of Devers

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
105	December	2016	$0	$0	$0	$0
106	January	2017	$0	$0	$0	$0
107	February	2017	$0	$0	$0	$0
108	March	2017	$0	$0	$0	$0
109	April	2017	$0	$0	$0	$0
110	May	2017	$0	$0	$0	$0
111	June	2017	$0	$0	$0	$0
112	July	2017	$0	$0	$0	$0
113	August	2017	$0	$0	$0	$0
114	September	2017	$0	$0	$0	$0
115	October	2017	$0	$0	$0	$0
116	November	2017	$0	$0	$0	$0
117	December	2017	$0	$0	$0	$0

f) Red Bluff

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
118	December	2016	$235,590,583	$19,587,100	$216,003,483	$0
119	January	2017	$235,590,583	$20,083,716	$215,506,867	$0
120	February	2017	$235,596,527	$20,580,331	$215,016,196	$5,944
121	March	2017	$235,599,878	$21,076,959	$214,522,919	$3,351
122	April	2017	$235,602,997	$21,573,594	$214,029,403	$3,119
123	May	2017	$235,602,997	$22,070,236	$213,532,761	$0
124	June	2017	$235,604,618	$22,566,878	$213,037,740	$1,621
125	July	2017	$235,604,618	$23,063,524	$212,541,094	$0
126	August	2017	$235,604,618	$23,560,169	$212,044,449	$0
127	September	2017	$235,604,618	$24,056,814	$211,547,803	$0
128	October	2017	$235,604,618	$24,553,460	$211,051,158	$0
129	November	2017	$235,653,735	$25,050,105	$210,603,630	$49,118
130	December	2017	$235,653,723	$25,546,854	$210,106,869	-$12

g) Whirlwind Substation Expansion

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
131	December	2016	$53,627,431	$3,026,415	$50,601,016	$0
132	January	2017	$53,627,431	$3,136,881	$50,490,550	$0
133	February	2017	$53,627,431	$3,247,348	$50,380,084	$0
134	March	2017	$53,627,431	$3,357,814	$50,269,617	$0
135	April	2017	$86,255,712	$3,468,280	$82,787,432	$32,628,281
136	May	2017	$86,423,087	$3,645,924	$82,777,163	$167,374
137	June	2017	$86,465,217	$3,823,912	$82,641,305	$42,131
138	July	2017	$86,496,127	$4,001,987	$82,494,140	$30,910
139	August	2017	$86,531,254	$4,180,126	$82,351,128	$35,127
140	September	2017	$86,558,720	$4,358,336	$82,200,383	$27,466
141	October	2017	$87,524,371	$4,536,604	$82,987,767	$965,651
142	November	2017	$87,519,888	$4,716,859	$82,803,029	-$4,483
143	December	2017	$87,531,655	$4,897,105	$82,634,551	$11,767

h) Colorado River Substation Expansion

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
144	December	2016	$71,091,079	$5,992,602	$65,098,477	$0
145	January	2017	$71,149,299	$6,139,912	$65,009,388	$58,220
146	February	2017	$71,330,024	$6,287,341	$65,042,683	$180,724
147	March	2017	$71,477,391	$6,435,142	$65,042,249	$147,367
148	April	2017	$71,530,278	$6,583,246	$64,947,031	$52,887
149	May	2017	$71,586,513	$6,731,460	$64,855,053	$56,235
150	June	2017	$71,611,412	$6,879,789	$64,731,623	$24,900
151	July	2017	$71,627,145	$7,028,169	$64,598,975	$15,733
152	August	2017	$71,640,094	$7,176,582	$64,463,511	$12,949
153	September	2017	$71,639,023	$7,325,022	$64,314,001	-$1,071
154	October	2017	$71,464,495	$7,473,459	$63,991,036	-$174,528
155	November	2017	$71,465,330	$7,621,547	$63,843,782	$835
156	December	2017	$71,499,907	$7,769,637	$63,730,269	$34,577

i) Mesa

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
157	December	2016	$0	$0	$0	$0
158	January	2017	$0	$0	$0	$0
159	February	2017	$0	$0	$0	$0
160	March	2017	$0	$0	$0	$0
161	April	2017	$0	$0	$0	$0
162	May	2017	$0	$0	$0	$0
163	June	2017	$0	$0	$0	$0
164	July	2017	$0	$0	$0	$0
165	August	2017	$0	$0	$0	$0
166	September	2017	$0	$0	$0	$0
167	October	2017	$0	$0	$0	$0
168	November	2017	$1,657,268	$0	$1,657,268	$1,657,268
169	December	2017	$1,657,268	$0	$1,657,268	$0

j) Alberhill

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
170	December	2016	$0	$0	$0	$0
171	January	2017	$0	$0	$0	$0
172	February	2017	$0	$0	$0	$0
173	March	2017	$0	$0	$0	$0
174	April	2017	$0	$0	$0	$0
175	May	2017	$0	$0	$0	$0
176	June	2017	$0	$0	$0	$0
177	July	2017	$0	$0	$0	$0
178	August	2017	$0	$0	$0	$0
179	September	2017	$0	$0	$0	$0
180	October	2017	$0	$0	$0	$0
181	November	2017	$0	$0	$0	$0
182	December	2017	$0	$0	$0	$0

k) ELM Series Caps

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
183	December	2016	$0	$0	$0	$0
184	January	2017	$0	$0	$0	$0
185	February	2017	$0	$0	$0	$0
186	March	2017	$0	$0	$0	$0
187	April	2017	$0	$0	$0	$0
188	May	2017	$0	$0	$0	$0
189	June	2017	$0	$0	$0	$0
190	July	2017	$0	$0	$0	$0
191	August	2017	$0	$0	$0	$0
192	September	2017	$0	$0	$0	$0
193	October	2017	$0	$0	$0	$0
194	November	2017	$0	$0	$0	$0
195	December	2017	$0	$0	$0	$0

6) Summary of Incentive Projects and incentives granted

	A) Rancho Vista Incentives Received:		**Cite:**
196	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
197	ROE adder:	0.75%	121 FERC ¶ 61,168 at P 129
198	100% Abandoned Plant:	No	-------
	B) Tehachapi Incentives Received:		**Cite:**
199	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
200	ROE adder:	1.25%	121 FERC ¶ 61,168 at P 129
201	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	C) Devers to Colorado River Incentives Received:		**Cite:**
202	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
203	ROE adder:	1.00%	121 FERC ¶ 61,168 at 129; modified by ER10-160 Settlement, see
204			P2 and P3
205	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	D) Devers to Palo Verde 2 Incentives Received:		**Cite:**
206	CWIP:	No	121 FERC ¶ 61,168 at P 57; modified by ER10-160 Settlement, see
207			P2 and P3
208	ROE adder:	0.00%	121 FERC ¶ 61,168 at P 129; modified by ER10-160 Settlement, see
209			P 3 and P 7
210	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	E) South of Kramer Incentives Received:		**Cite:**
211	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
212	ROE adder:	0.00%	---
213	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	F) West of Devers Incentives Received:		**Cite:**
214	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
215	ROE adder:	0.00%	---
216	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	G) Red Bluff Incentives Received:		**Cite:**
217	CWIP:	Yes	133 FERC ¶ 61,107 at P 76
218	ROE adder:	0.00%	133 FERC ¶ 61,107 at P 102
219	100% Abandoned Plant:	Yes	133 FERC ¶ 61,107 at P 88
	H) Whirlwind Substation Expansion Incentives Received:		**Cite:**
220	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
221	ROE adder:	0.00%	---
222	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	I) Colorado River Substation Expansion Incentives Received:		**Cite:**
223	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
224	ROE adder:	0.00%	---
225	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	J) Mesa		**Cite:**
226	CWIP:	Yes	161 FERC ¶ 61,107 at P35
227	ROE adder:	0.00%	---
228	100% Abandoned Plant:	No	---

	K) Alberhill		**Cite:**
229	CWIP:	Yes	161 FERC ¶ 61,107 at P35
230	ROE adder:	0.00%	---
231	100% Abandoned Plant:	Yes	161 FERC ¶ 61,107 at P 21
	L) ELM Series Caps		**Cite:**
232	CWIP:	Yes	161 FERC ¶ 61,107 at P35
233	ROE adder:	0.00%	---
234	100% Abandoned Plant:	Yes	161 FERC ¶ 61,107 at P 21
	M) Future Incentive Projects		**Cite:**
235	CWIP:		
236	ROE adder:		
237	100% Abandoned Plant:		
	…		

Instructions:

1) Upon Commission approval of any incentives for additional projects, add additional projects and provide cite to the Commission decision.

Determination of Incentive Adders Components of the TRR

Input data is shaded yellow

Two Incentive Adders are calculated:
a) The Prior Year Incentive Adder is a component of the Prior Year TRR.
b) The True Up Incentive Adder is a component of the True Up TRR.

1) Calculation of Incremental Return on Equity Factor

The Incremental Return on Equity Factor is the incremental Prior Year TRR expressed per 100 basis points of ROE incentive, for each million dollars of Incentive Net Plant. It is calculated according to the following formula:

IREF = CSCP * 0.01 * (1/(1 - CTR)) * $1,000,000

Line	where:		Value	Source
1	CSCP = Common Stock Capital Percentage		49.2250%	1-BaseTRR, L 47
2	CTR = Composite Tax Rate		27.9836%	1-BaseTRR, L 59
3		IREF =	$6,835	Above formula

2) Determination of multiplicative factors for use in calculating Incentive Adders:
Multiplicative factors are used to calculate the Incentive Adders on an Transmission Incentive Project specific basis.
Multiplicative factor for each project is the ratio of its ROE adder to 1%.

Line		ROE Adder	Multiplicative Factor	Source
4	1) Rancho Vista	0.75%	0.75	14-IncentivePlant, L 197
5	2) Tehachapi	1.25%	1.25	14-IncentivePlant, L 200
6	3) Devers to Col. River	1.00%	1.00	14-IncentivePlant, L 203
7				
8	…			

3) Calculation of Prior Year Incentive Adder (EOY)
1) Determine Prior Year Incentive Adder for each Incentive Project by multiplying the IREF, the Multiplicative Factor, and the million $ of Prior Year Incentive Rate Base.
2) Sum project-specific Incentive Adders to yield the total Prior Year Incentive Adder.

Line		Prior Year Incentive Rate Base	Multiplicative Factor	Prior Year Incentive Adder	Source
9	1) Rancho Vista	$150,232,043	0.75	$770,155	14-IncentivePlant, L 13, Col. 1
10	2) Tehachapi	$2,728,701,253	1.25	$23,314,193	14-IncentivePlant, L 14, Col. 1
11	3) Devers to Col. River	$687,752,340	1.00	$4,700,959	14-IncentivePlant, L 15, Col. 1
12					
13	…				
14			Prior Year Incentive Adder =	$28,785,307	Sum of above PY Incentive Adders for each individual project

4) Calculation of True-Up Incentive Adder
1) Determine True Up Incentive Adder for each Incentive Project by multiplying the IREF, the Multiplicative Factor, and the million $ of True Up Incentive Net Plant.
2) Sum project-specific Incentive Adders to yield the total True Up Incentive Adder.

Line		True-Up Incentive Net Plant	Multiplicative Factor	True-Up Incentive Adder	Source
15	1) Rancho Vista	$152,604,254	0.75	$782,316	14-IncentivePlant, L 19, Col. 1
16	2) Tehachapi	$2,756,592,235	1.25	$23,552,496	14-IncentivePlant, L 20, Col. 1
17	3) Devers to Col. River	$697,660,501	1.00	$4,768,684	14-IncentivePlant, L 21, Col. 1
18					
19	…				
20			True-Up Incentive Adder =	$29,103,495	Sum of above PY Incentive Adders for each individual project

5) Calculation of Total ROE for Plant-In Service in the True Up TRR

a) Transmission Incentive Plant Net Plant In Service

Line	Incentive Project	13-Month Avg. TIP Net Plant In Service	Source
21	1) Rancho Vista	$152,604,254	14-IncentivePlant, L 19, Col. 3
22	2) Tehachapi	$2,750,697,473	14-IncentivePlant, L 20, Col. 3
23	3) Devers to Col. River	$697,660,501	14-IncentivePlant, L 21, Col. 3
24			
	…		

b) Calculation of ROE Adders on TIP Net Plant In Service

Line	Incentive Project	Col 1 True Up Incentive Adder	Col 2 After-Tax True Up Incentive Adder	Source
25	1) Rancho Vista	$782,316	$563,396	See Note 1
26	2) Tehachapi	$23,502,130	$16,925,388	See Note 1
27	3) Devers to Col. River	$4,768,684	$3,434,234	See Note 1
28				See Note 1
29	…			
30		Total:	$20,923,018	

c) Equity Portion of Plant In Service Rate Base

Line		Amount	Source
31	Total Rate Base:	$5,447,682,122	4-TUTRR, Line 18
32	CWIP Portion of Rate Base:	$111,914,471	4-TUTRR, Line 14
33	Plant In Service Rate Base:	$5,335,767,651	Line 31 - Line 32
34	Equity percentage:	49.2250%	1-BaseTRR, Line 47
35	Equity Portion of Plant In Service Rate Base:	$2,626,532,057	Line 33 * Line 34

d) Total ROE for Plant In Service in the True Up TRR

Line			
36	Plant In Service ROE Adder Percentage:	0.80%	Line 30 / Line 35
37	Base ROE (Including 50 basis point		
38	CAISO Participation Adder):	17.62%	1-BaseTRR, Line 50
39	Total ROE for Plant In Service in True Up TRR:	18.42%	Line 36 + Line 38

Instructions:
1) If additional projects receive ROE adders, add to end of lists, and include in calculation of each Incentive Adder.

Notes:
1) Column 1: The True Up Incentive Adder for each Incentive Project equals the IREF on Line 3, times the applicable Multiplicative Factor on Lines 15 to 18, times the million $ of TIP Net Plant In Service on Lines 21 to 24.
Column 2: The After Tax True Up Incentive Adder is derived by multiplying the amounts in Column 1 by (1 - CTR) (Where the CTR is on Line 2).

Forecast Plant Additions for In-Service ISO Transmission Plant

Yellow shaded cells are Input Data

Forecast Plant Additions represents the total increase in ISO Transmission Net Plant, not including CWIP,
during the Rate Year, incremental to the year-end Prior Year amount.
It is calculated on a 13-Month Average Basis during the Rate Year.

1) Total Plant Additions Forecast (See Note 1)

Line	Forecast Period Month	Year	Col 1 See Note 2 Unloaded Total Plant Adds	Col 2 See Note 2 Prior Period CWIP Closed	Col 3 See Note 2 Over Heads Closed to PIS	Col 4 See Note 2 Cost of Removal	Col 5 See Note 2 AFUDC Eligible Plant Additions	Col 6 See Note 2 AFUDC	Col 7 See Note 2 Incremental Gross Plant	Col 8 See Note 2 Depreciation Accrual	Col 9 See Note 2 Incremental Reserve	Col 10 See Note 2 Net Plant	Col 11 See Note 2 Unloaded Low Voltage Additions	Col 12 See Note 2 Loaded Low Voltage Additions
1	January	2018	$19,115,721	$4,132,901	$1,123,712	$1,207,777	$13,889,440	$416,683	$19,448,339	$0	-$1,207,777	$20,656,116	$548,711	$557,820
2	February	2018	$15,694,355	$34,484	$1,174,490	$1,207,777	$13,889,440	$416,683	$35,526,090	$44,339	-$2,371,216	$37,897,306	$1,097,422	$1,115,640
3	March	2018	$15,102,583	$34,484	$1,130,107	$1,207,777	$13,889,440	$416,683	$50,967,686	$80,993	-$3,498,000	$54,465,686	$1,646,134	$1,673,459
4	April	2018	$17,901,937	$2,638,000	$1,144,795	$1,302,701	$14,981,058	$449,432	$69,161,150	$116,198	-$4,684,503	$73,845,653	$2,194,845	$2,231,279
5	May	2018	$14,864,406	$34,484	$1,112,244	$1,207,777	$13,889,440	$416,683	$84,346,706	$157,676	-$5,734,604	$90,081,311	$2,743,556	$2,789,099
6	June	2018	$95,174,450	$74,323,798	$1,563,799	$1,710,354	$19,669,074	$590,072	$179,964,674	$192,296	-$7,252,662	$187,217,336	$4,770,685	$4,849,878
7	July	2018	$14,713,160	$70,912	$1,098,169	$1,212,077	$13,938,890	$418,167	$194,982,092	$410,289	-$8,054,451	$203,036,543	$5,319,396	$5,407,698
8	August	2018	$14,376,069	$34,484	$1,075,619	$1,207,777	$13,889,440	$416,683	$209,642,686	$444,526	-$8,817,702	$218,460,388	$5,868,107	$5,965,518
9	September	2018	$14,428,377	$34,484	$1,079,542	$1,207,777	$13,889,440	$416,683	$224,359,512	$477,950	-$9,547,529	$233,907,041	$6,416,818	$6,523,337
10	October	2018	$14,727,807	$71,265	$1,099,241	$1,253,783	$14,418,501	$432,555	$239,365,332	$511,502	-$10,289,810	$249,655,142	$7,537,257	$7,662,375
11	November	2018	$14,125,406	$34,484	$1,056,819	$1,207,777	$13,889,440	$416,683	$253,756,463	$545,713	-$10,951,875	$264,708,338	$8,085,968	$8,220,195
12	December	2018	$139,623,547	$53,925,792	$6,427,332	$6,323,882	$72,724,640	$2,181,739	$395,665,199	$578,522	-$16,697,235	$412,362,434	$8,634,679	$8,778,015
13	January	2019	$14,345,567	$0	$1,075,918	$1,217,729	$14,003,881	$420,116	$410,289,072	$902,050	-$17,012,914	$427,301,985	$9,251,670	$9,405,248
14	February	2019	$13,364,280	$0	$1,002,321	$1,131,729	$13,014,881	$390,446	$423,914,390	$935,390	-$17,209,253	$441,123,643	$9,868,661	$10,032,480
15	March	2019	$13,520,671	$0	$1,014,050	$1,131,729	$13,014,881	$390,446	$437,707,829	$966,453	-$17,374,528	$455,082,358	$10,485,651	$10,659,713
16	April	2019	$13,715,286	$39,760	$1,025,664	$1,143,947	$13,155,390	$394,662	$451,699,494	$997,900	-$17,520,576	$469,220,070	$11,284,474	$11,471,796
17	May	2019	$19,727,727	$460,898	$1,445,012	$1,622,510	$18,658,868	$559,766	$471,809,489	$1,029,799	-$18,113,287	$489,922,776	$11,901,465	$12,099,029
18	June	2019	$19,806,746	$272,295	$1,465,084	$1,644,426	$18,910,904	$567,327	$492,004,219	$1,075,646	-$18,682,068	$510,686,287	$12,518,456	$12,726,262
19	July	2019	$47,944,709	$12,901,858	$2,628,214	$2,976,500	$34,229,749	$1,026,892	$540,627,534	$1,121,686	-$20,536,881	$561,164,415	$13,135,446	$13,353,495
20	August	2019	$27,702,986	$8,473,412	$1,442,218	$1,141,368	$13,125,733	$393,772	$569,025,142	$1,232,539	-$20,445,710	$589,470,852	$13,867,851	$14,098,058
21	September	2019	$13,612,716	$0	$1,020,954	$1,131,729	$13,014,881	$390,446	$582,917,529	$1,297,281	-$20,280,158	$603,197,687	$14,484,842	$14,725,290
22	October	2019	$45,081,505	$14,054,514	$2,327,024	$1,752,821	$20,157,439	$604,723	$629,177,961	$1,328,953	-$20,704,025	$649,881,986	$15,101,833	$15,352,523
23	November	2019	$31,728,969	$7,464,449	$1,819,839	$1,193,091	$13,720,543	$411,616	$661,945,294	$1,434,419	-$20,462,696	$682,407,991	$15,718,823	$15,979,756
24	December	2019	$47,725,059	$3,893,576	$3,287,361	$3,489,608	$40,130,496	$1,203,915	$710,672,021	$1,509,123	-$22,443,181	$733,115,202	$16,335,814	$16,606,988
25	13-Month Averages:								$521,342,706			$540,379,822		$12,714,512

2) Incentive Plant Forecast (See Note 1)

Line	Forecast Period Month	Year	Col 1 C4 10-CWIP L30-53 Unloaded Total Plant Adds	Col 2 C5 10-CWIP L30-53 Prior Period CWIP Closed	Col 3 C6 10-CWIP L30-53 Over Heads Closed to PIS	Col 4 N/A Cost of Removal	Col 5 N/A AFUDC Eligible Plant Additions	Col 6 N/A AFUDC	Col 7 = Prior Month C7 +C1+C3 Incremental Gross Plant	Col 8 = Prior Month C7 * L91/12 Depreciation Accrual	Col 9 = Prior Month C9 - C4 + C8 Reserve	Col 10 =C7-C9 Net Plant	Col 11 Unloaded Low Voltage Additions	Col 12 =C11* (1-L75) * (1+L74+L76) Loaded Low Voltage Additions
26	January	2018	$5,037,315	$4,098,417	$70,417	$0	$0	$0	$5,107,732	$0	$0	$5,107,732	$0	$0
27	February	2018	$1,615,948	$0	$121,196	$0	$0	$0	$6,844,877	$11,645	$11,645	$6,833,232	$0	$0
28	March	2018	$1,024,177	$0	$76,813	$0	$0	$0	$7,945,867	$15,605	$27,250	$7,918,617	$0	$0
29	April	2018	$116,255	$0	$8,719	$0	$0	$0	$8,070,841	$18,115	$45,365	$8,025,476	$0	$0
30	May	2018	$786,000	$0	$58,950	$0	$0	$0	$8,915,791	$18,400	$63,765	$8,852,026	$0	$0
31	June	2018	$3,410,370	$2,447,558	$72,211	$0	$0	$0	$12,398,371	$20,326	$84,092	$12,314,280	$0	$0
32	July	2018	$548,326	$0	$41,124	$0	$0	$0	$12,987,822	$28,266	$112,358	$12,875,464	$0	$0
33	August	2018	$297,663	$0	$22,325	$0	$0	$0	$13,307,810	$29,610	$141,968	$13,165,841	$0	$0
34	September	2018	$349,971	$0	$26,248	$0	$0	$0	$13,684,028	$30,340	$172,308	$13,511,721	$0	$0
35	October	2018	$77,673	$0	$5,825	$0	$0	$0	$13,767,527	$31,197	$203,505	$13,564,022	$0	$0
36	November	2018	$47,000	$0	$3,525	$0	$0	$0	$13,818,052	$31,388	$234,893	$13,583,159	$0	$0
37	December	2018	$20,677,884	$8,513,638	$912,318	$0	$0	$0	$35,408,255	$31,503	$266,395	$35,141,859	$0	$0
38	January	2019	$185,930	$0	$13,945	$0	$0	$0	$35,608,130	$80,725	$347,120	$35,261,009	$0	$0
39	February	2019	$204,643	$0	$15,348	$0	$0	$0	$35,828,120	$81,181	$428,301	$35,399,820	$0	$0
40	March	2019	$361,034	$0	$27,078	$0	$0	$0	$36,216,232	$81,682	$509,983	$35,706,249	$0	$0
41	April	2019	$373,816	$0	$28,036	$0	$0	$0	$36,618,084	$82,567	$592,550	$36,025,534	$0	$0
42	May	2019	$400,431	$0	$30,032	$0	$0	$0	$37,048,547	$83,483	$676,033	$36,372,514	$0	$0
43	June	2019	$413,213	$0	$30,991	$0	$0	$0	$37,492,751	$84,464	$760,497	$36,732,254	$0	$0
44	July	2019	$432,387	$0	$32,429	$0	$0	$0	$37,957,567	$85,477	$845,974	$37,111,593	$0	$0
45	August	2019	$14,427,934	$8,470,083	$446,839	$0	$0	$0	$52,832,340	$86,537	$932,511	$51,899,829	$0	$0
46	September	2019	$453,078	$0	$33,981	$0	$0	$0	$53,319,399	$120,449	$1,052,960	$52,266,440	$0	$0
47	October	2019	$19,987,218	$9,341,864	$798,402	$0	$0	$0	$74,105,019	$121,559	$1,174,519	$72,930,500	$0	$0
48	November	2019	$16,531,554	$6,140,181	$779,353	$0	$0	$0	$91,415,926	$168,947	$1,343,466	$90,072,460	$0	$0
49	December	2019	$5,786,285	$2,531,642	$244,098	$0	$0	$0	$97,446,309	$208,413	$1,551,879	$95,894,430	$0	$0

3) Non-Incentive Plant Forecast (See Note 1)

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
					=(C1-C2)*L74	=(C1-C2+C3)*L75	=C1-C2+C3-C4	=C5*L76	= Prior Month C2 +C2+C5+C6	= Prior Month C7 * L91/12	= Prior Month C9 - C4 + C8	=C7-C9		=C11* (1-L75) * (1+L74+L76)
Line	**Forecast Period Month**	**Year**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Cost of Removal**	**AFUDC Eligible Plant Additions**	**AFUDC**	**Incremental Gross Plant**	**Depreciation Accrual**	**Incremental Reserve**	**Net Plant**	**Unloaded Low Voltage Additions**	**Loaded Low Voltage Additions**
50	January	2018	$14,078,406	$34,484	$1,053,294	$1,207,777	$13,889,440	$416,683	$14,340,607	$0	-$1,207,777	$15,548,384	$548,711	$557,820
51	February	2018	$14,078,406	$34,484	$1,053,294	$1,207,777	$13,889,440	$416,683	$28,681,213	$32,694	-$2,382,861	$31,064,074	$1,097,422	$1,115,640
52	March	2018	$14,078,406	$34,484	$1,053,294	$1,207,777	$13,889,440	$416,683	$43,021,820	$65,388	-$3,525,250	$46,547,069	$1,646,134	$1,673,459
53	April	2018	$17,785,682	$2,638,000	$1,136,076	$1,302,701	$14,981,058	$449,432	$61,090,309	$98,082	-$4,729,868	$65,820,177	$2,194,845	$2,231,279
54	May	2018	$14,078,406	$34,484	$1,053,294	$1,207,777	$13,889,440	$416,683	$75,430,916	$139,276	-$5,798,370	$81,229,285	$2,743,556	$2,789,099
55	June	2018	$91,764,081	$71,876,240	$1,491,588	$1,710,354	$19,669,074	$590,072	$167,566,302	$171,970	-$7,336,754	$174,903,056	$4,770,685	$4,849,878
56	July	2018	$14,164,834	$70,912	$1,057,044	$1,212,077	$13,938,890	$418,167	$181,994,270	$382,023	-$8,166,809	$190,161,079	$5,319,396	$5,407,698
57	August	2018	$14,078,406	$34,484	$1,053,294	$1,207,777	$13,889,440	$416,683	$196,334,877	$414,916	-$8,959,670	$205,294,546	$5,868,107	$5,965,518
58	September	2018	$14,078,406	$34,484	$1,053,294	$1,207,777	$13,889,440	$416,683	$210,675,483	$447,610	-$9,719,837	$220,395,320	$6,416,818	$6,523,337
59	October	2018	$14,650,134	$71,265	$1,093,415	$1,253,783	$14,418,501	$432,555	$225,597,805	$480,305	-$10,493,315	$236,091,120	$7,537,257	$7,662,375
60	November	2018	$14,078,406	$34,484	$1,053,294	$1,207,777	$13,889,440	$416,683	$239,938,411	$514,325	-$11,186,767	$251,125,179	$8,085,968	$8,220,195
61	December	2018	$118,945,662	$45,412,154	$5,515,013	$6,323,882	$72,724,640	$2,181,739	$360,256,944	$547,019	-$16,963,630	$377,220,574	$8,634,679	$8,778,015
62	January	2019	$14,159,637	$0	$1,061,973	$1,217,729	$14,003,881	$420,116	$374,680,942	$821,325	-$17,360,034	$392,040,976	$9,251,670	$9,405,248
63	February	2019	$13,159,637	$0	$986,973	$1,131,729	$13,014,881	$390,446	$388,086,270	$854,209	-$17,637,554	$405,723,823	$9,868,661	$10,032,480
64	March	2019	$13,159,637	$0	$986,973	$1,131,729	$13,014,881	$390,446	$401,491,597	$884,771	-$17,884,511	$419,376,109	$10,485,651	$10,659,713
65	April	2019	$13,341,469	$39,760	$997,628	$1,143,947	$13,155,390	$394,662	$415,081,410	$915,333	-$18,113,125	$433,194,535	$11,284,474	$11,471,796
66	May	2019	$19,327,296	$460,898	$1,414,980	$1,622,510	$18,658,868	$559,766	$434,760,942	$946,315	-$18,789,320	$453,550,262	$11,901,465	$12,099,029
67	June	2019	$19,393,533	$272,295	$1,434,093	$1,644,426	$18,910,904	$567,327	$454,511,468	$991,181	-$19,442,565	$473,954,033	$12,518,456	$12,726,262
68	July	2019	$47,512,322	$12,901,858	$2,595,785	$2,976,500	$34,229,749	$1,026,892	$502,669,967	$1,036,209	-$21,382,856	$524,052,823	$13,135,446	$13,353,495
69	August	2019	$13,275,052	$3,330	$995,379	$1,141,368	$13,125,733	$393,772	$516,192,802	$1,146,003	-$21,378,221	$537,571,023	$13,867,851	$14,098,058
70	September	2019	$13,159,637	$0	$986,973	$1,131,729	$13,014,881	$390,446	$529,598,130	$1,176,832	-$21,333,117	$550,931,247	$14,484,842	$14,725,290
71	October	2019	$25,094,287	$4,712,650	$1,528,623	$1,752,821	$20,157,439	$604,723	$555,072,942	$1,207,394	-$21,878,544	$576,951,486	$15,101,833	$15,352,523
72	November	2019	$15,197,415	$1,324,267	$1,040,486	$1,193,091	$13,720,543	$411,616	$570,529,368	$1,265,473	-$21,806,162	$592,335,530	$15,718,823	$15,979,756
73	December	2019	$41,938,774	$1,361,933	$3,043,263	$3,489,608	$40,130,496	$1,203,915	$613,225,712	$1,300,711	-$23,995,060	$637,220,772	$16,335,814	$16,606,988

4) ISO Corporate Overhead Loader

Line		
74	ISO Corp OH Rate	7.50%

5) ISO Cost of Removal Percent

Line		
75	Cost of Removal Rate	8.00%

6) AFUDC Loader Rate

Line		
76	ISO AFUDC Rate	3.00%

7) Calculation of ISO Depreciation Rate

December Prior Year plant balances and accrual rates are as shown on Schedule 17 Depreciation

	Col 1	Col 2	Col 3	Col 4	
				C2*C3	
Line	**Acct**	**December Prior Year Plant Balance**	**Accrual Rate**	**Annual Accrual**	**Accrual Rate Reference**
77	**350.1**	$87,876,203	0.00%	$0	18 Dep Rates L1
78	**350.2**	$164,901,118	1.67%	$2,753,849	18 Dep Rates L2
79	**352**	$569,698,023	2.41%	$13,729,722	18 Dep Rates L3
80	**353**	$3,409,447,774	2.84%	$96,828,317	18 Dep Rates L4
81	**354**	$2,283,380,922	2.73%	$62,336,299	18 Dep Rates L5
82	**355**	$364,424,080	2.84%	$10,349,644	18 Dep Rates L6
83	**356**	$1,245,933,686	3.24%	$40,368,251	18 Dep Rates L7
84	**357**	$190,222,489	1.73%	$3,290,849	18 Dep Rates L8
85	**358**	$84,920,374	2.41%	$2,046,581	18 Dep Rates L9
86	**359**	$172,640,885	1.65%	$2,848,575	18 Dep Rates L10
87					
88	Sum of Depreciation Expense			$234,552,087	Sum of C4 Lines 77 to 86
89	Sum of Dec Prior Year Plant			$8,573,445,553	Sum of C2 Lines 77 to 86
90					
91	Composite Depreciation Rate			2.74%	Line 88 / Line 89

Notes:

1) Forecast Period is the calendar year two years after the Prior Year (i.e., PY+2).

2) Sum of Incentive Plant Calculations and Non-Incentive Calculations, lines 26-49 and lines 50-73

Depreciation Expense

Input cells are shaded yellow

1) Calculation of Depreciation Expense for Transmission Plant - ISO

Prior Year: 2017

Balances for Transmission Plant - ISO during the Prior Year, including December of previous year: **Source:** 6-PlantInService, Lines 1-13.

Line	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
		FERC Account:										
Line	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
1	Dec 2016	$86,845,703	$165,326,927	$531,582,611	$3,249,175,449	$2,233,991,232	$324,258,228	$1,235,903,791	$185,508,197	$81,951,072	$182,027,086	$8,276,570,295
2	Jan 2017	$81,997,511	$165,330,397	$528,854,083	$3,250,037,231	$2,231,001,014	$335,699,493	$1,232,564,516	$185,656,754	$81,997,920	$160,125,968	$8,253,264,889
3	Feb 2017	$82,013,020	$165,784,066	$534,882,418	$3,256,654,353	$2,213,130,982	$339,965,913	$1,235,030,894	$186,119,194	$82,775,424	$161,709,715	$8,258,065,980
4	Mar 2017	$82,413,677	$165,733,853	$532,806,954	$3,260,114,606	$2,225,922,423	$342,740,514	$1,241,178,225	$186,361,377	$83,455,651	$161,453,729	$8,282,181,008
5	Apr 2017	$82,424,960	$165,734,429	$540,340,485	$3,290,596,932	$2,251,979,965	$344,598,339	$1,244,265,048	$186,611,561	$83,540,944	$161,600,158	$8,351,692,820
6	May 2017	$82,438,880	$165,704,351	$548,767,497	$3,303,060,549	$2,258,078,709	$345,368,677	$1,242,476,528	$187,117,539	$83,717,689	$168,349,232	$8,385,079,651
7	Jun 2017	$81,409,531	$165,534,488	$552,041,270	$3,313,909,561	$2,261,350,618	$347,377,534	$1,244,803,717	$188,491,607	$84,190,542	$167,806,375	$8,406,915,244
8	Jul 2017	$81,421,876	$165,199,675	$554,107,049	$3,321,544,471	$2,263,663,368	$350,109,485	$1,244,039,916	$188,624,718	$84,257,050	$167,839,950	$8,420,807,557
9	Aug 2017	$81,875,011	$164,728,138	$558,293,842	$3,350,799,129	$2,265,082,996	$350,778,178	$1,246,103,080	$188,962,876	$84,383,656	$168,194,579	$8,459,201,484
10	Sep 2017	$81,886,831	$164,709,520	$560,085,940	$3,354,129,789	$2,263,017,844	$354,174,067	$1,247,812,337	$189,290,136	$84,485,994	$168,808,262	$8,468,400,720
11	Oct 2017	$81,898,670	$164,708,798	$557,690,365	$3,337,803,870	$2,267,000,466	$357,358,231	$1,247,335,361	$189,937,864	$84,808,333	$169,009,660	$8,457,551,618
12	Nov 2017	$87,866,111	$164,907,957	$559,289,849	$3,340,005,249	$2,268,750,108	$362,445,561	$1,244,772,136	$190,107,796	$84,849,890	$171,154,663	$8,474,149,320
13	Dec 2017	$87,876,203	$164,901,118	$569,698,023	$3,409,447,774	$2,283,380,922	$364,424,080	$1,245,933,686	$190,222,489	$84,920,374	$172,640,885	$8,573,445,553
14												

15 Depreciation Rates (Percent per year) See Instruction 1.

16	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359
17a	Dec 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17b	Jan 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17c	Feb 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17d	Mar 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17e	Apr 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17f	May 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17g	Jun 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17h	Jul 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17i	Aug 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17j	Sep 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17k	Oct 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17l	Nov 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17m	Dec 2017	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%

18

19 Monthly Depreciation Expense for Transmission Plant - ISO by FERC Account: See Note 1 and Instruction 1

20

Line												
21		FERC										
22		Account:										Month
23	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
24	Jan 2017	$0	$228,702	$1,138,473	$6,687,886	$4,542,449	$991,690	$3,141,255	$255,074	$264,292	$236,635	$17,486,456
25	Feb 2017	$0	$228,707	$1,132,629	$6,689,660	$4,536,369	$1,026,681	$3,132,768	$255,278	$264,443	$208,164	$17,474,699
26	Mar 2017	$0	$229,335	$1,145,540	$6,703,280	$4,500,033	$1,039,729	$3,139,037	$255,914	$266,951	$210,223	$17,490,041
27	Apr 2017	$0	$229,265	$1,141,095	$6,710,403	$4,526,042	$1,048,215	$3,154,661	$256,247	$269,144	$209,890	$17,544,962
28	May 2017	$0	$229,266	$1,157,229	$6,773,145	$4,579,026	$1,053,897	$3,162,507	$256,591	$269,420	$210,080	$17,691,161
29	Jun 2017	$0	$229,224	$1,175,277	$6,798,800	$4,591,427	$1,056,253	$3,157,961	$257,287	$269,990	$218,854	$17,755,072
30	Jul 2017	$0	$228,989	$1,182,288	$6,821,131	$4,598,080	$1,062,396	$3,163,876	$259,176	$271,514	$218,148	$17,805,599
31	Aug 2017	$0	$228,526	$1,186,713	$6,836,846	$4,602,782	$1,070,752	$3,161,935	$259,359	$271,729	$218,192	$17,836,833
32	Sep 2017	$0	$227,874	$1,195,679	$6,897,062	$4,605,669	$1,072,797	$3,167,179	$259,824	$272,137	$218,653	$17,916,873
33	Oct 2017	$0	$227,848	$1,199,517	$6,903,917	$4,601,470	$1,083,182	$3,171,523	$260,274	$272,467	$219,451	$17,939,650
34	Nov 2017	$0	$227,847	$1,194,387	$6,870,313	$4,609,568	$1,092,921	$3,170,311	$261,165	$273,507	$219,713	$17,919,730
35	Dec 2017	$0	$228,123	$1,197,812	$6,874,844	$4,613,125	$1,108,479	$3,163,796	$261,398	$273,641	$222,501	$17,943,720
36	Totals:	$0	$2,743,707	$14,046,640	$81,567,286	$54,906,038	$12,706,990	$37,886,809	$3,097,586	$3,239,236	$2,610,503	
37								Total Annual Depreciation Expense for Transmission Plant - ISO:				$212,804,795
38											(equals sum of monthly amounts)	

Line							
39	**2) Calculation of Depreciation Expense for Distribution Plant - ISO**						
40							
41		**360**	**361**	**362**			**Source**
42	Distribution Plant - ISO BOY	$0	$0	$0			6-PlantInService Line 15.
43	Distribution Plant - ISO EOY	$0	$0	$0			6-PlantInService Line 16.
44	Average BOY/EOY :	$0	$0	$0			
45							
46	Depreciation Rates (Percent per year) See "18-DepRates".						
47		**360**	**361**	**362**			
48		1.67%	2.39%	2.01%			
49							
50	Depreciation Expense for Distribution Plant - ISO		See Note 2 and Instruction 2				
51							
52		**360**	**361**	**362**	**Total**		
53		$0	$0	$0		$0	Total is sum of Depreciation Expense for accounts
54							360, 361, and 362
55							
56	**3) Calculation of Depreciation Expense for General Plant and Intangible Plant**						
57							
58	Total General Plant Depreciation Expense					236,723,303	FF1 336.10f
59	Total Intangible Plant Depreciation Expense					238,988,799	FF1 336.1f
60	Sum of Total General and Total Intangible Depreciation Expense					$475,712,102	Line 58 + Line 59
61	Transmission Wages and Salaries Allocation Factor					6.0143%	27-Allocators, Line 9
62	General and Intangible Depreciation Expense					$28,610,926	Line 60 * Line 61
63							
64	**4) Depreciation Expense**						
65							
66	Depreciation Expense is the sum of:			**Amount**	**Source**		
67	1) Depreciation Expense for Transmission Plant - ISO			$212,804,795	Line 37, Col 12		
68	2) Depreciation Expense for Distribution Plant - ISO			$0	Line 53		
69	3) General and Intangible Depreciation Expense			$28,610,926	Line 62		
70	Depreciation Expense:			$241,415,721	Line 67 + Line 68 + Line 69		

Notes:

1) Depreciation Expense for each account for each month is equal to the previous month balance of Transmission Plant - ISO for that same account, times the Monthly Depreciation Rate for that account. Monthly rate = annual rates on Line 17a etc. divided by 12.
2) Depreciation Expense for each account is equal to the Average BOY/EOY value on Line 44 times the Depreciation Rate on Line 48.

Instructions:

1) Depreciation rates on lines 17a-17m are input based on the stated values of ISO Transmission Plant depreciation rates from Schedule 18 of the Formula Rate Spreadsheet in effect during the Prior Year.
2) In the event that depreciation rates stated on Schedule 18 to be applied to Distribution Plant - ISO are revised mid-year, calculate Depreciation Expense for for Distribution Plant - ISO on Line 53 utilizing the weighted-average (by time) of the annual depreciation rates in effect in the Prior Year.

Depreciation Rates

1) Transmission Plant - ISO

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
1	350.1	Fee Land	0.00%	0.00%	0.00%
2	350.2	Easements	1.67%	0.00%	1.67%
3	352	Structures and Improvements	1.79%	0.62%	2.41%
4	353	Station Equipment	2.39%	0.45%	2.84%
5	354	Towers and Fixtures	1.20%	1.53%	2.73%
6	355	Poles and Fixtures	1.06%	1.78%	2.84%
7	356	Overhead Conductors and Devices	0.78%	2.46%	3.24%
8	357	Underground Conduit	1.73%	0.00%	1.73%
9	358	Underground Conductors and Devices	1.62%	0.79%	2.41%
10	359	Roads and Trails	1.65%	0.00%	1.65%
11					

2) Distribution Plant - ISO

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
12	360	Land and Land Rights	1.67%	0.00%	1.67%
13	361	Structures and Improvements	1.75%	0.64%	2.39%
14	362	Station Equipment	1.32%	0.69%	2.01%

3) General Plant

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
15	389	Land and Land Rights	1.67%	0.00%	1.67%
16	390	Structures and Improvements	1.81%	0.27%	2.08%
17	391.1	Office Furniture	5.00%	0.00%	5.00%
18	391.5	Office Equipment	20.00%	0.00%	20.00%
19	391.6	Duplicating Equipment	20.00%	0.00%	20.00%
20	391.2	Personal Computers	20.00%	0.00%	20.00%
21	391.3	Mainframe Computers	20.00%	0.00%	20.00%
22	391.7	PC Software	20.00%	0.00%	20.00%
23	391.4	DDSMS - CPU & Processing	14.29%	0.00%	14.29%
24	391.4	DDSMS - Controllers, Receivers, Comm.	10.00%	0.00%	10.00%
25	391.4	DDSMS - Telemetering & System	6.67%	0.00%	6.67%
26	391.4	DDSMS - Miscellaneous	5.00%	0.00%	5.00%
27	391.4	DDSMS - Map Board	4.00%	0.00%	4.00%
28	393	Stores Equipment	5.00%	0.00%	5.00%
29	395	Laboratory Equipment	6.67%	0.00%	6.67%
30	398	Misc Power Plant Equipment	5.00%	0.00%	5.00%
31	397	Data Network Systems	20.00%	0.00%	20.00%
32	397	Telecom System Equipment	14.29%	0.00%	14.29%
33	397	Netcomm Radio Assembly	10.00%	0.00%	10.00%
34	397	Microwave Equip. & Antenna Assembly	6.67%	0.00%	6.67%
35	397	Telecom Power Systems	5.00%	0.00%	5.00%
36	397	Fiber Optic Communication Cables	4.00%	0.00%	4.00%
37	397	Telecom Infrastructure	2.50%	0.00%	2.50%
38	392	Transportation Equip.	14.29%	0.00%	14.29%
39	394.4	Garage & Shop -- Equip.	10.00%	0.00%	10.00%
40	394.5	Tools & Work Equip. -- Shop	10.00%	0.00%	10.00%
41	396	Power Oper Equip	6.67%	0.00%	6.67%

4) Intangible Plant

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
42	302	Hydro Relicensing	2.47%	0.00%	2.47%
43	303	Radio Frequency	2.50%	0.00%	2.50%
44	301	Other Intangibles	5.00%	0.00%	5.00%
45	303	Cap Soft 5yr	20.31%	0.00%	20.31%
46	303	Cap Soft 7yr	14.62%	0.00%	14.62%
47	303	Cap Soft 10yr	12.93%	0.00%	12.93%
48	303	Cap Soft 15yr	8.48%	0.00%	8.48%

Operations and Maintenance Expenses

Cells shaded yellow are input cells

1) Determination of Adjusted Operations and Maintenance Expenses for each account (Note 1)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
		= C3 + C4			Note 2	= C7 + C8			= C10 + C11	= C3 + C7	= C4 + C8
		Total Recorded O&M Expenses			Adjustments				Adjusted Recorded O&M Expenses		
	Account/Work Activity Rev	**Total**	**Labor**	**Non-Labor**	**Reason**	**Total**	**Labor**	**Non-Labor**	**Total**	**Labor**	**Non-Labor**
Line	**Transmission Accounts**										
1	560 - Operations Supervision and Engineering - Allocated	$7,342,064	$3,520,700	$3,821,363	G	-$208,296	$0	($208,296)	7,133,768	3,520,700	3,613,067
2	560 - Sylmar/Palo Verde	$147,369	$0	$147,369		$0	$0	$0	147,369	-	147,369
3	561 Load Dispatch - Allocated	$10,517,816	$8,215,416	$2,302,400		$0	$0	$0	10,517,816	8,215,416	2,302,400
4	561.400 Scheduling, System Control and Dispatch Services	$39,115,071	$0	$39,115,071	A	-$39,115,071	$0	($39,115,071)	-	-	-
5	561.500 Reliability Planning and Standards Development	$5,180,971	$3,963,546	$1,217,425		$0	$0	$0	5,180,971	3,963,546	1,217,425
6	562 - Station Expenses - Allocated	$21,150,924	$17,264,529	$3,886,395		$0	$0	$0	21,150,924	17,264,529	3,886,395
7	562 - MOGS Station Expense	$74	$0	$74	B	-$74	$0	($74)	-	-	-
8	562 - Sylmar/Palo Verde	$1,032,205	$0	$1,032,205		$0	$0	$0	1,032,205	-	1,032,205
9	563 - Overhead Line Expenses - Allocated	$4,733,731	$3,855,139	$878,593		$0	$0	$0	4,733,731	3,855,139	878,593
10	564 - Underground Line Expenses - Allocated	$1,390,335	$1,156,422	$233,913		$0	$0	$0	1,390,335	1,156,422	233,913
11	565 - Transmission of Electricity by Others	-$267,657	$0	($267,657)		$0	$0	$0	(267,657)	-	(267,657)
12	565 - Wheeling Costs	$9,539,403	$0	$9,539,403	C	-$9,539,403	$0	($9,539,403)	-	-	-
13	565 - WAPA Transmission for Remote Service	$243,420	$0	$243,420		$0	$0	$0	243,420	-	243,420
14	566 - Miscellaneous Transmission Expenses - Allocated	$44,312,184	$21,104,376	$23,207,808	F	-$10,311	($6,802)	($3,509)	44,301,873	21,097,574	23,204,300
15	566 - ISO/RSBA/TSP Balancing Accounts	-$34,008,593	$59,372	($34,067,965)	D	$34,008,593	($59,372)	$34,067,965	-	-	-
16	566 - Sylmar/Palo Verde/Other General Functions	$944,338	$0	$944,338		$0	$0	$0	944,338	-	944,338
17	567 - Line Rents - Allocated	$15,401,559	$5,529	$15,396,031		$0	$0	$0	15,401,559	5,529	15,396,031
18	567 - Eldorado	$107,252	$0	$107,252		$0	$0	$0	107,252	-	107,252
19	567 - Sylmar/Palo Verde	$189,601	$0	$189,601		$0	$0	$0	189,601	-	189,601
20	568 - Maintenance Supervision and Engineering - Allocated	$2,384,824	$2,049,482	$335,342		$0	$0	$0	2,384,824	2,049,482	335,342
21	568 - Sylmar/Palo Verde	$192,594	$0	$192,594		$0	$0	$0	192,594	-	192,594
22	569 - Maintenance of Structures - Allocated	$36,080,406	$42,017	$36,038,389	E	-$32,917,251	$0	($32,917,251)	3,163,155	42,017	3,121,138
23	569 - Sylmar/Palo Verde	$242,950	$0	$242,950		$0	$0	$0	242,950	-	242,950
24	570 - Maintenance of Station Equipment - Allocated	$10,828,014	$5,048,010	$5,780,004		$0	$0	$0	10,828,014	5,048,010	5,780,004
25	570 - Sylmar/Palo Verde	$1,655,073	$744	$1,654,329		$0	$0	$0	1,655,073	744	1,654,329
26	571 - Maintenance of Overhead Lines - Allocated	$38,881,912	$9,142,174	$29,739,737	F	-$4,213,792	($7,564)	($4,206,228)	34,668,120	9,134,611	25,533,509
27	571 - Sylmar/Palo Verde	$393,017	$0	$393,017		$0	$0	$0	393,017	-	393,017
28	572 - Maintenance of Underground Lines - Allocated	$388,987	$203,478	$185,509		$0	$0	$0	388,987	203,478	185,509
29	572 - Sylmar/Palo Verde	$2,322	$0	$2,322		$0	$0	$0	2,322	-	2,322
30	573 - Maintenance of Miscellaneous Trans. Plant - Allocated	$2,970,934	$1,053,187	$1,917,747		$0	$0	$0	2,970,934	1,053,187	1,917,747
31	…	---	---	---	---	$0	---	---			
32	Transmission NOIC (Note 3)	-	-	-		$11,010,552	$11,010,552	$0	$11,010,552	$11,010,552	$0
33	**Total Transmission O&M**	$221,093,098	$76,684,121	$144,408,977		-$40,985,053	$10,936,814	-$51,921,867	$180,108,045	$87,620,934	$92,487,110
34											

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
		= C3 + C4			Note 2	= C7 + C8			= C10 + C11	= C3 + C7	= C4 + C8
		Total Recorded O&M Expenses			Adjustments				Adjusted Recorded O&M Expenses		
	Account/Work Activity Rev	Total	Labor	Non-Labor	Reason	Total	Labor	Non-Labor	Total	Labor	Non-Labor
	Distribution Accounts										
35	582 - Station Expenses	35,012,491	$26,445,838	$8,566,653		-	$0	$0	35,012,491	26,445,838	8,566,653
36	590 - Maintenance Supervision and Engineering	2,386,348	$2,048,869	$337,479		-	$0	$0	2,386,348	2,048,869	337,479
37	591 - Maintenance of Structures	72,359	$7,390	$64,969		-	$0	$0	72,359	7,390	64,969
38	592 - Maintenance of Station Equipment	10,261,821	$5,375,622	$4,886,200		-	$0	$0	10,261,821	5,375,622	4,886,200
39	Accounts with no ISO Distribution Costs	475,672,744	$203,269,818	$272,402,926	F	(7,072,865)	($458,229)	($6,614,636)	468,599,879	202,811,590	265,788,290
40	Distribution NOIC (Note 3)	-	-	-		34,050,403	34,050,403	-	34,050,403	34,050,403	-
41	**Total Distribution O&M**	523,405,764	237,147,537	286,258,227		26,977,538	33,592,174	(6,614,636)	550,383,302	270,739,711	279,643,591
42											
43	**Total Transmission and Distribution O&M**	744,498,862	313,831,657	430,667,204		(14,007,515)	44,528,988	(58,536,503)	730,491,347	358,360,646	372,130,701
44											
45	Total Transmission O&M Expenses in FERC Form 1:	$221,093,099	FF1 321.112b	Must equal Line 33, Column 2.							
46	Total Distribution O&M Expenses in FERC Form 1:	$523,405,763	FF1 322.156b	Must equal Line 41, Column 2.							
47	Total TDBU NOIC	$45,060,955	20-AandG, Note 2, f								

2) Determination of ISO Operations and Maintenance Expenses for each account (Note 5).

Line	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
		From C9 above	From C10 above	From C11 above	Note 6	= C7 + C8	= C3 * C5	= C4 * C5	
		Adjusted Recorded O&M Expenses			Percent	ISO O&M Expenses			Percent ISO
	Account/Work Activity Rev	Total	Labor	Non-Labor	ISO	Total	Labor	Non-Labor	Reference
	Transmission Accounts								
48	560 - Operations Supervision and Engineering - Allocated	7,133,768	3,520,700	3,613,067	36.6%	2,614,413	1,290,281	1,324,132	27-Allocators Line 42
49	560 - Sylmar/Palo Verde	147,369	-	147,369	100.0%	147,369	-	147,369	100%
50	561 Load Dispatch - Allocated	10,517,816	8,215,416	2,302,400	36.6%	3,854,613	3,010,820	843,793	27-Allocators Line 42
51	561.400 Scheduling, System Control and Dispatch Services	-	-	-	0.0%	-	-	-	0%
52	561.500 Reliability Planning and Standards Development	5,180,971	3,963,546	1,217,425	100.0%	5,180,971	3,963,546	1,217,425	100%
53	562 - Station Expenses - Allocated	21,150,924	17,264,529	3,886,395	36.6%	7,751,479	6,327,177	1,424,302	27-Allocators Line 42
54	562 - MOGS Station Expense	-	-	-	0.0%	-	-	-	0%
55	562 - Sylmar/Palo Verde	1,032,205	-	1,032,205	100.0%	1,032,205	-	1,032,205	100%
56	563 - Overhead Line Expenses - Allocated	4,733,731	3,855,139	878,593	46.8%	2,213,224	1,802,444	410,780	27-Allocators Line 30
57	564 - Underground Line Expenses - Allocated	1,390,335	1,156,422	233,913	1.4%	20,123	16,737	3,386	27-Allocators Line 36
58	565 - Transmission of Electricity by Others	(267,657)	-	(267,657)	100.0%	(267,657)	-	(267,657)	100%
59	565 - Wheeling Costs	-	-	-	0.0%	-	-	-	0%
60	565 - WAPA Transmission for Remote Service	243,420	-	243,420	0.0%	-	-	-	0%
61	566 - Miscellaneous Transmission Expenses - Allocated	44,301,873	21,097,574	23,204,300	36.6%	16,235,936	7,731,927	8,504,009	27-Allocators Line 42
62	566 - ISO/RSBA/TSP Balancing Accounts	-	-	-	0.0%	-	-	-	0%
63	566 - Sylmar/Palo Verde/Other General Functions	944,338	-	944,338	100.0%	944,338	-	944,338	100%
64	567 - Line Rents - Allocated	15,401,559	5,529	15,396,031	46.8%	7,200,893	2,585	7,198,309	27-Allocators Line 30
65	567 - Eldorado	107,252	-	107,252	100.0%	107,252	-	107,252	100%
66	567 - Sylmar/Palo Verde	189,601	-	189,601	100.0%	189,601	-	189,601	100%
67	568 - Maintenance Supervision and Engineering - Allocated	2,384,824	2,049,482	335,342	36.6%	874,000	751,103	122,898	27-Allocators Line 42
68	568 - Sylmar/Palo Verde	192,594	-	192,594	100.0%	192,594	-	192,594	100%
69	569 - Maintenance of Structures - Allocated	3,163,155	42,017	3,121,138	36.6%	1,159,246	15,398	1,143,848	27-Allocators Line 42
70	569 - Sylmar/Palo Verde	242,950	-	242,950	100.0%	242,950	-	242,950	100%
71	570 - Maintenance of Station Equipment - Allocated	10,828,014	5,048,010	5,780,004	36.6%	3,968,296	1,850,016	2,118,280	27-Allocators Line 42
72	570 - Sylmar/Palo Verde	1,655,073	744	1,654,329	100.0%	1,655,073	744	1,654,329	100%
73	571 - Maintenance of Overhead Lines - Allocated	34,668,120	9,134,611	25,533,509	46.8%	16,208,842	4,270,825	11,938,017	27-Allocators Line 30
74	571 - Sylmar/Palo Verde	393,017	-	393,017	100.0%	393,017	-	393,017	100%
75	572 - Maintenance of Underground Lines - Allocated	388,987	203,478	185,509	1.4%	5,630	2,945	2,685	27-Allocators Line 36
76	572 - Sylmar/Palo Verde	2,322	-	2,322	100.0%	2,322	-	2,322	100%
77	573 - Maintenance of Miscellaneous Trans. Plant - Allocated	2,970,934	1,053,187	1,917,747	36.6%	1,088,800	385,976	702,824	27-Allocators Line 42
78	…	---	---	---	---	---	---	---	
79	Transmission NOIC (Note 4)	11,010,552	11,010,552	-		4,516,089	4,516,089	-	
80	**Total Transmission - ISO O&M**	180,108,045	87,620,934	92,487,110		77,531,619	35,938,613	41,593,006	
81									

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
		From C9 above	From C10 above	From C11 above	Note 6	= C7 + C8	= C3 * C5	= C4 * C5	
		Adjusted Recorded O&M Expenses			Percent	ISO O&M Expenses			Percent ISO
	Account/Work Activity Rev	Total	Labor	Non-Labor	ISO	Total	Labor	Non-Labor	Reference
	Distribution Accounts								
82	582 - Station Expenses	35,012,491	26,445,838	8,566,653	0.0%	-	-	-	27-Allocators Line 48
83	590 - Maintenance Supervision and Engineering	2,386,348	2,048,869	337,479	0.0%	-	-	-	27-Allocators Line 48
84	591 - Maintenance of Structures	72,359	7,390	64,969	0.0%	-	-	-	27-Allocators Line 48
85	592 - Maintenance of Station Equipment	10,261,821	5,375,622	4,886,200	0.0%	-	-	-	27-Allocators Line 48
86	Accounts with no ISO Distribution Costs	468,599,879	202,811,590	265,788,290	0.0%	-	-	-	0%
87	Distribution NOIC (Note 4)	34,050,403	34,050,403	-	0.0%	-	-	-	0%
88	**Total Distribution - ISO O&M**	550,383,302	270,739,711	279,643,591		-	-	-	
89									
90									
91	**Total ISO O&M Expenses (in Column 6)**	730,491,347	358,360,646	372,130,701		77,531,619	35,938,613	41,593,006	
92	Line 80 + Line 88								

Notes:

1) "Adjusted Operations and Maintenance Expenses for each account" are the total amounts of O&M costs booked to each Transmission or Distribution account, less adjustments as noted.

2) Reasons for excluded amounts:
A: Exclude entire amount, all attributable to CAISO costs recovered in Energy Resource Recovery Account.
B: Exclude amount related to MOGS Station Expense.
C: Exclude amount attributable to CAISO costs recovered in Energy Resource Recovery Account.
D: Exclude amount recovered through to Reliability Services Balancing Account, the Transmission Access Charge Balancing Account Adjustment, and the American Reinvestment Recovery Act for the Tehachapi Wind Energy Storage Project.
E: Exclude amount of costs transfered to account from A&G Account 920 pursuant to Order 668.
F: Excludes shareholder funded costs.
G: Exclude EEI & EPRI Dues Re-Mapped to FERC Account 930.2 Miscellaneous general expenses.

3) Total TDBU NOIC is allocated to Transmission and Distribution in proportion to labor in the respective functions. Transmission NOIC ("Non-Officer Incentive Compensation") equals Total TDBU NOIC times the Transmission NOIC Percentage calculated below. Distribution NOIC equals Total TDBU NOIC times the Distribution NOIC Percentage below.

Total TDBU NOIC is on Line: 47

	Percentage	Calculation
Transmission NOIC Percentage:	24.4348%	Line 33, Col 3 / Line 43, Col 3
Distribution NOIC Percentage:	75.5652%	Line 41, Col 3 / Line 43, Col 3

4) NOIC attributable to ISO Transmission (Column 7) is calculated utilizing a percentage equal to the ratio of total ISO O&M Labor Expenses in column 7 (exclusive of NOIC) to the total labor expenses in column 3 (exclusive of NOIC). That allocator, which is identified below, is then applied to the value in Column 3 to arrive at the NOIC attributable to ISO Transmission in Column 7.
Resulting Percentage is: 41.02%

5) "ISO Operations and Maintenance Expenses" is the amount of costs in each Transmission or Distribution account related to ISO Transmission Facilities.

6) See Column 9 for references to source of each Percent ISO.

7) SCE shall make no adjustments to recorded labor amounts related to non-labor labor and/or Indirect labor in Schedule 19.

Calculation of Administrative and General Expense

Inputs are shaded yellow

Line	Acct.	Description	Col 1 FERC Form 1 Amount	Col 2 Data Source	Col 3 See Note 1 Total Amount Excluded	Col 4 A&G Expense	Notes
1	920	A&G Salaries	$354,859,044	FF1 323.181b	$44,861,861	$309,997,183	
2	921	Office Supplies and Expenses	$249,803,334	FF1 323.182b	$5,610,135	$244,193,199	
3	922	A&G Expenses Transferred	-$145,897,634	FF1 323.183b	-$48,972,720	-$96,924,914	Credit
4	923	Outside Services Employed	$54,121,017	FF1 323.184b	$7,684,282	$46,436,735	
5	924	Property Insurance	$14,497,978	FF1 323.185b	$0	$14,497,978	
6	925	Injuries and Damages	$117,581,984	FF1 323.186b	-$695,634	$118,277,618	
7	926	Employee Pensions and Benefits	$142,806,958	FF1 323.187b	-$37,470,824	$180,277,782	
8	927	Franchise Requirements	$110,632,750	FF1 323.188b	$110,632,750	$0	
9	928	Regulatory Commission Expenses	$16,012,736	FF1 323.189b	$17,351,998	-$1,339,262	
10	929	Duplicate Charges	$0	FF1 323.190b	$0	$0	
11	930.1	General Advertising Expense	$5,718,074	FF1 323.191b	$0	$5,718,074	
12	930.2	Miscellaneous General Expense	$34,422,373	FF1 323.192b	$24,004,996	$10,417,377	
13	931	Rents	$6,627,867	FF1 323.193b	$11,411,119	-$4,783,252	
14	935	Maintenance of General Plant	$13,296,044	FF1 323.196b	$697,671	$12,598,373	
15			$974,482,525		Total A&G Expenses:	$839,366,892	

Line		Amount	Source
16	Remaining A&G after exclusions & NOIC Adjustment:	$839,366,892	Line 15
17	Less Account 924:	$14,497,978	Line 5
18	Amount to apply the Transmission W&S AF:	$824,868,914	Line 16 - Line 17
19	Transmission Wages and Salaries Allocation Factor:	6.0143%	27-Allocators, Line 9
20	Transmission W&S AF Portion of A&G:	$49,610,390	Line 18 * Line 19
21	Transmission Plant Allocation Factor:	19.1484%	27-Allocators, Line 22
22	Property Insurance portion of A&G:	$2,776,134	Line 5 Col 4 * Line 21
23	Administrative and General Expenses:	$52,386,525	Line 20 + Line 22

Note 1: Itemization of exclusions

Line	Acct.	Total Amount Excluded (Sum of Col 1 to Col 4)	Col 1 Shareholder Exclusions or Other Adjustments	Col 2 Franchise Requirements	Col 3 NOIC	Col 4 PBOPs	Notes
24	920	$44,861,861	-$28,840,749		$73,702,610		See Instructions 2b, 3, and Note 2
25	921	$5,610,135	$5,610,135		$0		
26	922	-$48,972,720	-$7,655,813		-$41,316,907		
27	923	$7,684,282	$7,684,282		$0		
28	924	$0	$0		$0		
29	925	-$695,634	-$695,634		$0		
30	926	-$37,470,824	-$2,461,672		$0	-$35,009,152	See Note 3
31	927	$110,632,750	$0	$110,632,750	$0	$0	See Note 4
32	928	$17,351,998	$17,351,998		$0		
33	929	$0	$0		$0		
34	930.1	$0	$0		$0		
35	930.2	$24,004,996	$24,004,996		$0		
36	931	$11,411,119	$11,411,119		$0		
37	935	$697,671	$697,671		$0		

Note 2: Non-Officer Incentive Compensation ("NOIC") Adjustment

Adjust NOIC by excluding accrued NOIC Amount and replacing with the actual non-capitalized A&G NOIC payout.

		Amount	Source
a	Accrued NOIC Amount:	$103,811,325	SCE Records
b	Actual A&G NOIC payout:	$30,108,715	Note 2, d
c	Adjustment:	$73,702,610	

Actual non-capitalized NOIC Payouts:

	Department		Amount	Source
d	A&G		$30,108,715	SCE Records and Workpapers
e	Other		$13,613,013	SCE Records and Workpapers
f	Trans. And Dist. Business Unit		$45,060,955	SCE Records and Workpapers
g		Total:	$88,782,682	Sum of d to f

Note 3: PBOPs Exclusion Calculation

		Amount	Note:
a	Current Authorized PBOPs Expense Amount:	$18,219,000	See instruction #4
b	Prior Year Authorized PBOPs Expense Amount:	$40,055,779	Authorized PBOPs Expense Amount during Prior Year
c	Prior Year FF1 PBOPs expense:	$5,046,627	SCE Records
d	PBOPs Expense Exclusion:	-$35,009,152	c - b

Note 4:

Amount in Line 31, column 2 equals amount in Line 8, column 1 because all Franchise Requirements Expenses are excluded
Franchise Fees Expenses component of the Prior Year TRR are based on Franchise Fee Factors.

Instructions:

1) Enter amounts of A&G expenses from FERC Form 1 in Lines 1 to 14.
2) Fill out "Itemization of Exclusions" table for all input cells. NOIC amount in Column 3, Line 24 is calculated in Note 2. The PBOPs exclusion in Column 4, Line 30 is calculated in Note 3.
a) Exclude amount of any Shareholder Adjustments, costs incurred on behalf of SCE shareholders, from relevant account in Column 1.
b) Include as an adjustment in Column 1 for Account 920 any amount excluded from Accounts 569.100, 569.200, and 569.300 in Schedule 19 (OandM) related to Order 668 costs transferred.
c) Exclude entire amount of account 927 "Franchise Requirements" in Column 2, as those costs are recovered through the Franchise Fees Expense item.
d) Exclude any amount of Account 930.1 "General Advertising Expense" not related to advertising for safety, siting, or informational purposes in column 1.
e) Exclude any amount of expense relating to secondary land use and audit expenses not directly benefitting utility customers.
f) Exclude from account 930.2:
1) Nuclear Power Research Expenses.
2) Write Off of Abandoned Project Expenses.
3) Any advertising expenses within the Consultants/Professional Services category.
g) Exclude the following costs included in any account 920-935:
1) Any amount of "Provision for Doubtful Accounts" costs.
2) Any amount of "Accounting Suspense" costs.
3) Any penalties or fines.
4) Any amount of costs recovered 100% through California Public Utilities Commission ("CPUC") rates.
3) NOIC adjustment in Column 3**,** Line 24 is made by determining the difference between the total accrued NOIC amount included in the FERC Form 1 recorded cost amounts and the actual A&G NOIC payout (see note 2).
NOIC adjustment in column 3, Line 26 is made by entering the amount of accrued NOIC that is capitalized.
4) Determine the PBOPs exclusion. The authorized amount of PBOPs expense (line a) may only be revised pursuant to Commission acceptance of an SCE FPA Section 205 filing to revise the authorized PBOPs expense, in accordance with the tariff protocols. Accordingly, any amount different than the authorized PBOPs expense during the Prior Year is excluded from account 926 (see note 3). Docket or Decision approving authorized PBOPs amount: ER19-1226
5) SCE shall make no adjustments to recorded labor amounts related to non-labor labor and/or Indirect labor in Schedule 20.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
1a	450	4191110	Late Payment Charge- Comm. & Ind.	5,873,550	Traditional OOR	5,873,550	0	5,873,550	0			0	0	1
1b	450	4191115	Residential Late Payment	11,837,660	Traditional OOR	11,837,660	0	11,837,660	0			0	0	1
2	**450 Total**			**17,711,210**		**17,711,210**	**0**	**17,711,210**	**0**		**0**	**0**	**0**	
3	**FF-1 Total for Acct 450 - Forfeited Discounts, p300.16b (Must Equal Line 2)**			**17,711,210**										
4a	451	4182110	Recover Unauthorized Use/Non-Energy	113,379	Traditional OOR	113,379	0	113,379	0			0	0	1
4b	451	4182115	Miscellaneous Service Revenue - Ownership Cost	364,706	Traditional OOR	364,706	0	364,706	0			0	0	1
4c	451	4192110	Miscellaneous Service Revenues	33,304,278	Traditional OOR	33,304,278	0	33,304,278	0			0	0	1
4d	451	4192115	Returned Check Charges	1,427,740	Traditional OOR	1,427,740	0	1,427,740	0			0	0	1
4e	451	4192125	Service Reconnection Charges	5,877	Traditional OOR	5,877	0	5,877	0			0	0	1
4f	451	4192130	Service Establishment Charge	456	Traditional OOR	456	0	456	0			0	0	1
4g	451	4192140	Field Collection Charges	340	Traditional OOR	340	0	340	0			0	0	1
4h	451	4192510	Quickcheck Revenue	44	GRSM	0	0	0	44	P	0	44	0	2
4i	451	4192910	PUC Reimbursement Fee-Elect	411,073	Other Ratemaking	0	0	0	0			0	411,073	6
4j	451	4182120	Uneconomic Line Extension	228	Traditional OOR	228	0	228	0			0	0	1
4k	451	4192152	Opt Out CARE-Res-Ini	1,560	Other Ratemaking	0	0	0	0			0	1,560	1
4l	451	4192155	Opt Out CARE-Res-Mo	34,655	Other Ratemaking	0	0	0	0			0	34,655	1
4m	451	4192158	Opt Out NonCARE-Res-Ini	45,600	Other Ratemaking	0	0	0	0			0	45,600	1
4n	451	4192160	Opt Out NonCARE-Res-Mo	251,230	Other Ratemaking	0	0	0	0			0	251,230	1
4o	451	4192135	Conn-Charge - Residential	5,815,681	Traditional OOR	5,815,681	0	5,815,681	0			0	0	1
4p	451	4192145	Conn-Charge - Non-Residential	2,178,888	Traditional OOR	2,178,888	0	2,178,888	0			0	0	1
4q	451	4192150	Conn-Charge - At Pole	22,027	Traditional OOR	22,027	0	22,027	0			0	0	1
5	**451 Total**			**43,977,762**		**43,233,600**	**0**	**43,233,600**	**44**		**0**	**44**	**744,118**	
6	**FF-1 Total for Acct 451 - Misc. Service Revenues, p300.17b (Must Equal Line 5)**			**43,977,762**										
8	**453 Total**			**0**		**0**	**0**	**0**	**0**		**0**	**0**	**0**	
9	**FF-1 Total for Acct 453 - Sales of Water and Power, p300.18b (Must Equal Line 8)**			**0**										
10a	454	4184110	Joint Pole - Tariffed Conduit Rental	548,369	Traditional OOR	548,369	0	548,369	0			0	0	4
10b	454	4184112	Joint Pole - Tariffed Pole Rental - Cable Cos.	3,349,084	Traditional OOR	3,349,084	0	3,349,084	0			0	0	4
10c	454	4184114	Joint Pole - Tariffed Process & Eng Fees - Cable	426,320	Traditional OOR	426,320	0	426,320	0			0	0	4
10d	454	4184120	Joint Pole - Aud - Unauth Penalty	718,500	Traditional OOR	718,500	0	718,500	0			0	0	4
10e	454	4184510	Joint Pole - Non-Tariffed Pole Rental	146,982	GRSM	0	0	0	146,982	P	29,678	117,304	0	2
10f	454	4184512	Joint Pole - Non-Tariff Process & Engineering Fees	9,240	GRSM	0	0	0	9,240	P	1,004	8,236	0	2
10g	454	4184514	Joint Pole - Non-Tariff Requests for Information	18,880	GRSM	0	0	0	18,880	P	17,840	1,040	0	2
10h	454	4184516	Oil And Gas Royalties	13,134	GRSM	0	0	0	13,134	P	2,112	11,022	0	2
10i	454	4184518	Def Operating Land & Facilities Rent Rev	(787,609)	Traditional OOR	(787,609)	0	(787,609)	0			0	0	4
10j	454	4184810	Facility Cost -EIX/Nonutility	60,454	Other Ratemaking	3,578	3,578	0	0			0	56,876	6, 12
10k	454	4184815	Facility Cost- Utility		Traditional OOR	0	0	0	0			0	0	7
10l	454	4184820	Rent Billed to Non-Utility Affiliates	1,344,451	Other Ratemaking	79,578	79,578	0	0			0	1,264,873	6, 12
10m	454	4184825	Rent Billed to Utility Affiliates		Traditional OOR	0	0	0	0			0	0	7
10n	454	4194110	Meter Leasing Revenue		Traditional OOR	0	0	0	0			0	0	1
10o	454	4194115	Company Financed Added Facilities	10,649,093	Traditional OOR	10,649,093	0	10,649,093	0			0	0	4
10p	454	4194120	Company Financed Interconnect Facilities	747,196	Traditional OOR	747,196	0	747,196	0			0	0	4
10q	454	4194130	SCE Financed Added Faclty	22,731,825	Traditional OOR	22,731,825	0	22,731,825	0			0	0	4
10r	454	4194135	Interconnect Facility Finance Charge	13,246,533	Traditional OOR	13,246,533	3,119,188	10,127,345	0			0	0	8
10s	454	4204515	Operating Land & Facilities Rent Revenue	21,987,089	GRSM	0	0	0	21,987,089	P	4,456,797	17,530,293	0	2
10t	454	4867020	Nonoperating Misc Land & Facilities Rent		Traditional OOR	0	0	0	0			0	0	4
10u	454	-	Miscellaneous Adjustments	(35,871)	Traditional OOR	(35,871)	0	(35,871)	0			0	0	1
10v	454	4206515	Op Misc Land/Fac Rev	1,353,393	GRSM	0	0	0	1,353,393	P	272,458	1,080,936	0	2
10w	454	4184122	T-Unauth Pole Rent		Traditional OOR	0	0	0	0			0	0	4
10x	454	4184124	T-P&E Fees	5,840	Traditional OOR	5,840	0	5,840	0			0	0	4
10y	454	4184821	Rent Rev NU-NonBRRBA	84,600	Other Ratemaking	5,007	5,007	0	0			0	79,592	6, 12
10z	454	4184811	Fac Cost N/U-BRRBA	960,791	Other Ratemaking	56,869	56,869	0	0			0	903,922	6, 12
10aa	454	4184515	NEM 2.0	1,848,475	Other Ratemaking	0	0	0	0			0	1,848,475	6
11	**454 Total**			**79,426,770**		**51,744,313**	**3,264,221**	**48,480,091**	**23,528,719**		**4,779,889**	**18,748,830**	**4,153,738**	
12	**FF-1 Total for Acct 454 - Rent from Elec. Property, p300.19b (Must Equal Line 11)**			**79,426,770**										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
12a	456	4186114	Energy Related Services	3,857,356	Traditional OOR	3,857,356	0	3,857,356	0			0	0	1
12b	456	4186118	Distribution Miscellaneous Electric Revenues	576	Traditional OOR	576	0	576	0			0	0	4
12c	456	4186120	Added Facilities - One Time Charge	133,080	Traditional OOR	133,080	0	133,080	0			0	0	4
12d	456	4186122	Building Rental - Nev Power/Mohave Cr		Traditional OOR	0	0	0	0			0	0	3
12e	456	4186126	Service Fee - Optimal Bill Prd	160	Traditional OOR	160	0	160	0			0	0	1
12f	456	4186128	Miscellaneous Revenues	803,911	Traditional OOR	803,911	0	803,911	0			0	0	1
12g	456	4186130	Tule Power Plant - Revenue		Traditional OOR	0	0	0	0			0	0	3
12h	456	4186142	Microwave Agreement	3,428	Traditional OOR	3,428	0	3,428	0			0	0	4
12i	456	4186150	Utility Subs Labor Markup		Traditional OOR	0	0	0	0			0	0	7
12j	456	4186155	Non Utility Subs Labor Markup	8,005	Other Ratemaking	474	474	0	0			0	7,531	6, 12
12k	456	4186162	Reliant Eng FSA Ann Pymnt-Mandalay	1,447	Traditional OOR	1,447	0	1,447	0			0	0	4
12l	456	4186164	Reliant Eng FSA Ann Pymnt-Ormond Beach	14,522	Traditional OOR	14,522	0	14,522	0			0	0	4
12m	456	4186166	Reliant Eng FSA Ann Pymnt-Etiwanda	4,388	Traditional OOR	4,388	0	4,388	0			0	0	4
12n	456	4186168	Reliant Eng FSA Ann Pymnt-Ellwood	993	Traditional OOR	993	0	993	0			0	0	4
12o	456	4186170	Reliant Eng FSA Ann Pymnt-Coolwater	845	Traditional OOR	845	0	845	0			0	0	4
12p	456	4186194	Property License Fee revenue	173,880	Traditional OOR	173,880	0	173,880	0			0	0	4
12q	456	4186512	Revenue From Recreation, Fish & Wildlife	1,965,774	GRSM	0	0	0	1,965,774	P	315,815	1,649,958	0	2
12r	456	4186514	Mapping Services	161,225	GRSM	0	0	0	161,225	P	37,883	123,342	0	2
12s	456	4186518	Enhanced Pump Test Revenue	40,875	GRSM	0	0	0	40,875	P	84	40,791	0	2
12t	456	4186524	Revenue From Scrap Paper - General Office		GRSM	0	0	0	0	P		0	0	2
12u	456	4186528	CTAC Revenues	1,700	GRSM	0	0	0	1,700	P	0	1,700	0	2
12v	456	4186530	AGTAC Revenues	3,775	GRSM	0	0	0	3,775	P	2,775	1,000	0	2
12w	456	4186716	ADT Vendor Service Revenue		GRSM	0	0	0	0	A		0	0	2
12xx	456	4186718	Read Water Meters - Irvine Ranch		GRSM	0	0	0	0	A		0	0	2
12yy	456	4186720	Read Water Meters - Rancho California		GRSM	0	0	0	0	A		0	0	2
12zz	456	4186722	Read Water Meters - Long Beach		GRSM	0	0	0	0	A		0	0	2
12aa	456	4186730	SSID Transformer Repair Services Revenue	56,262	GRSM	0	0	0	56,262	A	20,209	36,053	0	2
12bb	456	4186815	Employee Transfer/Affiliate Fee		Other Ratemaking	0	0	0	0			0	0	6
12cc	456	4186910	ITCC/CIAC Revenues	25,076,869	Traditional OOR	25,076,869	0	25,076,869	0			0	0	4
12dd	456	4186912	Revenue From Decommission Trust Fund	(450,696,490)	Other Ratemaking	0	0	0	0			0	(450,696,490)	6
12ee	456	4186914	Revenue From Decommissioning Trust FAS115	(11,397,579)	Other Ratemaking	0	0	0	0			0	(11,397,579)	6
12ff	456	4186916	Offset to Revenue from NDT Earnings/Realized	450,696,234	Other Ratemaking	0	0	0	0			0	450,696,234	6
12gg	456	4186918	Offset to Revenue from FAS 115 FMV	11,397,579	Other Ratemaking	0	0	0	0			0	11,397,579	6
12hh	456	4186920	Revenue From Decommissioning Trust FAS115-1	38,748,032	Other Ratemaking	0	0	0	0			0	38,748,032	6
12ii	456	4186922	Offset to Revenue from FAS 115-1 Gains & Loss	(38,748,032)	Other Ratemaking	0	0	0	0			0	(38,748,032)	6
12jj	456	4188712	Power Supply Installations - IMS		GRSM	0	0	0	0	A		0	0	2
12kk	456	4188714	Consulting Fees - IMS		GRSM	0	0	0	0	A		0	0	2
12ll	456	4196105	DA Revenue	137,952	Traditional OOR	137,952	0	137,952	0			0	0	1
12mm	456	4196158	EDBL Customer Finance Added Facilities	4,720,962	Traditional OOR	4,720,962	0	4,720,962	0			0	0	4
12nn	456	4196162	SCE Energy Manager Fee Based Services	139,470	Traditional OOR	139,470	0	139,470	0			0	0	4
12oo	456	4196166	SCE Energy Manager Fee Based Services Adj		Traditional OOR	0	0	0	0			0	0	4
12pp	456	4196172	Off Grid Photo Voltaic Revenues		Traditional OOR	0	0	0	0			0	0	1
12qq	456	4196174	Scheduling/Dispatch Revenues		Traditional OOR	0	0	0	0			0	0	4
12rr	456	4196176	Interconnect Facilities Charges-Customer Financed	3,322,797	Traditional OOR	3,322,797	24,628	3,298,169	0			0	0	8
12ss	456	4196178	Interconnect Facilities Charges - SCE Financed	15,018,441	Traditional OOR	15,018,441	0	15,018,441	0			0	0	4
12tt	456	4196184	DMS Service Fees	2,757	Traditional OOR	2,757	0	2,757	0			0	0	4
12uu	456	4196188	CCA - Information Fees	435,631	Traditional OOR	435,631	0	435,631	0			0	0	6
12vv	456	-	Miscellaneous Adjustments	513	Traditional OOR	513	0	513	0			0	0	1
12ww	456	4186911	Grant Amortization	4,866,855	Other Ratemaking	0	0	0	0			0	4,866,855	6
12xx	456	4186925	GHG Allowance Revenue	384,894,152	Other Ratemaking	0	0	0	0			0	384,894,152	6
12yy	456	4186132	Intercon One Time	1,589,445	Traditional OOR	1,589,445	0	1,589,445	0			0	0	4
12zz	456	4186116	EV Charging Revenue		Traditional OOR	0	0	0	0			0	0	4
12aaa	456	4186115	Energy Reltd Srv-TSP	95,177	Traditional OOR	95,177	0	95,177	0			0	0	4
12bbb	456	4186156	N/U Labor Mrkp-BRRBA	131,685	Other Ratemaking	7,794	7,794	0	0			0	123,890	6, 12
12ccc	456	4188720	LCFS CR 411.8	19,405,750	Traditional OOR	19,405,750	0	19,405,750	0			0	0	4
12ddd	456	4186128	Miscellaneous Revenues - ISO	5,000	Traditional OOR	5,000	5,000	0	0			0	0	5
12eee	456	4186732	Power Quality C&I Customer Program	12,000	GRSM	0	0	0	12,000	P	0	12,000	0	2
13	**456 Total**			**467,087,400**		**74,953,617**	**37,896**	**74,915,721**	**2,241,611**		**376,767**	**1,864,844**	**389,892,172**	
14	**FF-1 Total for Acct 456 - Other electric Revenues, p300.21b (Must Equal Line 13)**			**467,087,400**										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR			GRSM			Other Ratemaking	
Line	**FERC ACCT**	**ACCT**	**ACCT DESCRIPTION**	**DOLLARS**	**Category**	**Total**	**ISO**	**Non-ISO**	**Total**	**A/P**	**Threshold [10]**	**Incremental**	**Total**	**Notes**
15a	456.1	4188112	Trans of Elec of Others - Pasadena		Traditional OOR	0	0	0	0			0	0	5
15b	456.1	4188114	FTS PPU/Non-ISO	296,028	Traditional OOR	296,028	0	296,028	0			0	0	4
15c	456.1	4188116	FTS Non-PPU/Non-ISO	930,163	Traditional OOR	930,163	0	930,163	0			0	0	4
15d	456.1	4188812	ISO-Wheeling Revenue - Low Voltage	151,885	Other Ratemaking	0	0	0	0			0	151,885	6
15e	456.1	4188814	ISO-Wheeling Revenue - High Voltage	74,458,175	Other Ratemaking	0	0	0	0			0	74,458,175	6
15f	456.1	4188816	ISO-Congestion Revenue		Other Ratemaking	0	0	0	0			0	0	6
15g	456.1	4198110	Transmission of Elec of Others	46,329,301	Traditional OOR	46,329,301	46,329,301	0	0			0	0	5
15h	456.1	4198112	WDAT	5,560,313	Traditional OOR	5,560,313	0	5,560,313	0			0	0	4
15i	456.1	4198114	Radial Line Rev-Base Cost - Reliant Coolwater	(574,575)	Traditional OOR	(574,575)	0	(574,575)	0			0	0	4
15j	456.1	4198116	Radial Line Rev-Base Cost - Reliant Ormond Beach	1,080,948	Traditional OOR	1,080,948	0	1,080,948	0			0	0	4
15k	456.1	4198118	Radial Line Rev-O&M - AES Huntington Beach	402,148	Traditional OOR	402,148	0	402,148	0			0	0	4
15l	456.1	4198120	Radial Line Rev-O&M - Reliant Mandalay	209,706	Traditional OOR	209,706	0	209,706	0			0	0	4
15m	456.1	4198122	Radial Line Rev-O&M - Reliant Coolwater	89,265	Traditional OOR	89,265	0	89,265	0			0	0	4
15n	456.1	4198124	Radial Line Rev-O&M - Ormond Beach	651,331	Traditional OOR	651,331	0	651,331	0			0	0	4
15o	456.1	4198126	High Desert Tie-Line Rental Rev	264,133	Traditional OOR	264,133	0	264,133	0			0	0	4
15p	456.1	4198130	Inland Empire CRT Tie-Line EX	42,492	Traditional OOR	42,492	0	42,492	0			0	0	4
15q	456.1	4198910	Reliability Service Revenue - Non-PTO's	285,798	Other Ratemaking	0	0	0	0			0	285,798	6
15r	456.1	4198132	Radial Line Agreement-Base-Mojave Solr	90,533	Traditional OOR	90,533	0	90,533	0			0	0	4
15s	456.1	4198134	Radial Line Agreement-O&M-Mojave Solr	229,854	Traditional OOR	229,854	0	229,854	0			0	0	4
15t	456.1	4188716	ISO Non-Refundable Interconnection Deposit	3,708,123	Other Ratemaking	0	0	0	0			0	3,708,123	6
16	**456.1 Total**			**134,205,621**		**55,601,640**	**46,329,301**	**9,272,339**	**0**		**0**	**0**	**78,603,981**	
17	**FF-1 Total for Account 456.1 - Revenues from Trans. Of Electricity of Others, p300.22b (Must Equal Line 16)**			**134,205,621**										
18a														
19	**457.1 Total**			**0**		**0**	**0**	**0**	**0**		**0**	**0**	**0**	
20	**FF-1 Total for Account 457.1 - Regional Control Service Revenues, p300.23b (Must Equal Line 19)**			**0**										
21a														
22	**457.2 Total**			**0**		**0**	**0**	**0**	**0**		**0**	**0**	**0**	
23	**FF-1 Total for Account 457.2- Miscellaneous Revenues, p300.24b (Must Equal Line 22)**			**0**										
	Edison Carrier Solutions (ECS)													
24a	417	4863130	ECS - Distribution Facilities	605,719	GRSM	0	0	0	605,719	P	138,132	467,587	0	2
24b	417	4862110	ECS - Dark Fiber	6,207,732	GRSM	0	0	0	6,207,732	A	1,179,301	5,028,431	0	2
24c	417	4862115	ECS - SCE Net Fiber	3,328,620	GRSM	0	0	0	3,328,620	A	648,086	2,680,534	0	2
24d	417	4862120	ECS - Transmission Right of Way	283,556	GRSM	0	0	0	283,556	A	55,208	228,348	0	2
24e	417	4862135	ECS - Wholesale FCC	21,488,152	GRSM	0	0	0	21,488,152	A	4,216,369	17,271,783	0	2
24f	417	4864115	ECS - EU FCC Rev	(237,195)	GRSM	0	0	0	(237,195)	A	114,302	(351,497)	0	2
24g	417	4862125	ECS - Cell Site Rent and Use (Active)	13,328,277	GRSM	0	0	0	13,328,277	A	2,561,825	10,766,452	0	2
24h	417	4862130	ECS - Cell Site Reimbursable (Active)	4,452,839	GRSM	0	0	0	4,452,839	A	1,066,218	3,386,621	0	2
24i	417	4863120	ECS - Communication Sites	342,231	GRSM	0	0	0	342,231	P	71,854	270,376	0	2
24j	417	4863110	ECS - Cell Site Rent and Use (Passive)	3,528,304	GRSM	0	0	0	3,528,304	P	685,429	2,842,874	0	2
24k	417	4863115	ECS - Cell Site Reimbursable (Passive)	873,100	GRSM	0	0	0	873,100	P	325,605	547,495	0	2
24l	417	4863125	ECS - Micro Cell	1,970,237	GRSM	0	0	0	1,970,237	P	365,770	1,604,468	0	2
24m	417	4864120	ECS - End User Universal Service Fund Fee	(42,477)	GRSM	0	0	0	(42,477)	A	21,210	(63,687)	0	2
24n	417	4864116	ECS - Instrastate End User Revenue	1,330,785	GRSM	0	0	0	1,330,785	A	60,758	1,270,027	0	2
24o	417	4864121	ECS - Intrastate End User Fees	107,810	GRSM	0	0	0	107,810	A	4,665	103,145	0	2
24p	417	4864117	ECS - Interstate End User Tax Exempt	40,857	GRSM	0	0	0	40,857	A	0	40,857	0	2
24q	417	4864122	ECS- EU USAC E-Rate	27,607	GRSM	0	0	0	27,607	A	0	27,607	0	2
25	**417 ECS Total**			**57,636,155**		**0**	**0**	**0**	**57,636,155**		**11,514,733**	**46,121,422**	**0**	
26	**417 Other**			**7,774,304**										
27	**FF-1 Total for Account 417 - Revenues From Nonutility Operations p117.33c (Must Equal Line 25 + 26)**			**65,410,459**										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
						Traditional OOR			GRSM				Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
	Subsidiaries													
28a	418.1		ESI (Gross Revenues - Active)		GRSM	0	0	0	0	A		0	0	2,9
28b	418.1		ESI (Gross Revenues - Passive)		GRSM	0	0	0	0	P		0	0	2,9
28c	418.1		Southern States Realty	0	GRSM	0	0	0	0	P		0	0	2, 15
28d	418.1		Mono Power Company	(45)	Traditional OOR	(45)	0	(45)	0			0	0	13
28e	418.1		Edison Material Supply (EMS)	(1,824,113)	Traditional OOR	(1,824,113)	(107,969)	(1,716,143)	0			0	0	7, 17
29	**418.1 Subsidiaries Total**			**(1,824,158)**		**(1,824,158)**	**(107,969)**	**(1,716,188)**	**0**		**0**	**0**	**0**	
30	**418.1 Other (See Note 16)**			**1,824,113**										
31	**FF-1 Total for Account 418.1 -Equity in Earnings of Subsidiary Companies, p117.36c (Must Equal Line 29 + 30)**			**(45)**										
32			**Totals**	**798,220,762**		**241,420,223**	**49,523,449**	**191,896,774**	**83,406,529**		**16,671,389**	**66,735,140**	**473,394,010**	

Line		Description	Amount	Calculation
33		Ratepayers' Share of Threshold Revenue	16,671,389	= Line 32K
34		ISO Ratepayers' Share of Threshold Revenue	5,425,127	Note 11
35				
36		Total Active Incremental Revenue	40,424,675	= Sum Active categories in column L
37		Ratepayers' Share of Active Incremental Revenue	4,042,467	= Line 36D * 10%
38		Total Passive Incremental Revenue	26,310,465	= Sum Passive categories in column L
39		Ratepayers' Share of Passive Incremental Revenue	7,893,139	= Line 38D * 30%
40		Total Ratepayers' Share of Incremental Revenue	11,935,607	= Line 37D + Line 39D
41		ISO Ratepayers' Share of Incremental Revenue (%)	32.54%	see Note 11
42		ISO Ratepayers' Share of Incremental Revenue	3,884,030	= Line 40D * Line 41D
43		**Tot. ISO Ratepayers' Share NTP&S Gross Rev.**	**9,309,157**	= Line 34D + Line 42D

Line		Amount	Calculation
44	**Total Revenue Credits:**	$58,832,606	Sum of Column D, Line 43 and Column G, Line 32

Notes:

1- CPUC Jurisdictional service related.

2- Subject to sharing per the Gross Revenue Sharing Mechanism (GRSM), adopted in CPUC D.99-09-070. On an annual basis, once SCE obtains $16,671,389.55 (Threshold Revenue) in NTP&S Revenues, any additional revenues (Incremental Gross Revenues) that SCE receives are shared between shareholders and ratepayers. For GRSM categories deemed Active, the Incremental Gross Revenues are shared 90/10 between shareholders and ratepayers. For those categories deemed Passive, the Incremental Gross Revenues are shared 70/30 between shareholders and ratepayers.

3- Generation related.

4- Non-ISO facilities related.

5- ISO transmission system related.

6- Subject to balancing account treatment

7- Allocated based on CPUC GRC allocator in effect during the Prior Year. The weighted average (by time) shall be used if more than one allocator is in effect during the Prior Year.
ISO Allocator = 0.05919 Source: CPUC D. 15-11-021

8- ISO portion of Traditional OOR relates to monthly revenues received from customers for facilities that are part of the ISO network.

9- Edison ESI is a subsidiary company. Gross revenues are not reported in FF-1, only net earnings. Net Earnings for ESI are reported on Acct 418.1, pg 225.5e.

10- The first $16,671,389 million in gross revenues generated by GRSM activities are automatically classified as Threshold Revenue.

11- Allocator is equal to the jurisdictional split of the Threshold Revenue, which is jurisdictionalized as $5.425M to FERC ratepayers and $11.246M to CPUC ratepayers per the 2009 CPUC General Rate Case (D. 09-03-025). The ISO ratepayers' share of ratepayer revenue is $5.425M/$16.671M = 32.54%.

12- Allocated based on the CPUC Base Revenue Requirement Balancing Account (BRRBA) allocator in effect during the Prior Year. The weighted average (by time) shall be used if more than one allocator is in effect during the Prior Year. ISO portion of revenue is treated as traditional OOR.

ISO Allocator = 0.05919 Source: CPUC D. 15-11-021

13- Mono Power Company is a subsidiary company. Net Earnings are reported on Acct 418.1, pg 225.11e. Revenues and costs shall be non-ISO.

14- SCE Capital Company is a subsidiary company. Net Earnings are reported on Acct 418.1, pg 225.23e. Revenues and costs shall be non-ISO.

15- Southern States Realty is a subsidiary company. Gross revenues are not reported in FF-1, only net earnings. Net Earnings for Southern States Realty are reported on Acct 418.1, pg 225.17e.

16- For subsidiaries that are subject to GRSM, Column D contains gross revenues. Input on Line 30D contains the associated expenses.

17- Per GRC Decision D.87-12-066, for ratemaking purposes EMS financials are consolidated with SCE's. See FERC Form 1 page 123.3 under "Equity Investment Differences" . Consequently, net income of EMS is not reported separately in FERC Form 1 and is not a part of FERC Account 418.1 totals. To ensure that ratepayers receive the net income from this subsidiary SCE includes EMS net income in the formula on line 28f. This amount is reversed as part of line 30 to remain consistent with the totals reported in FERC Form 1.

NETWORK UPGRADE CREDIT AND INTEREST EXPENSE

Prior Year: 2017

Line		Balance	Notes
	1) Beginning of Year Balances: (Note 1)		
1	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	$119,779,556	See Note 1
2	Acct 252 Other	$91,604,742	Line 3 - Line 1
3	Total Acct 252 - Customer Advances for Construction	$211,384,298	FF1 113.56d
	2) End of Year Balances: (Note 2)		
4	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	$93,345,105	See Note 3
5	Acct 252 Other	$79,619,300	Line 6 - Line 4
6	Total Acct 252 - Customer Advances for Construction	$172,964,405	FF1 113.56c
7	Average Outstanding Network Upgrade Credits Beginning and End of Year	$106,562,330	(Line 1 + Line 4) / 2
8	Interest On Network Upgrade Credits Recorded in FERC Acct 242	$6,116,851	See Note 4
9	Acct 242 Other	$664,223,662	Line 10 - Line 8
10	Total Acct 242 - Miscellaneous Current and Accrued Liabilities	$670,340,513	FF1 113.48c

Notes:

1 Beginning of Year Balances are from December of the year previous to the Prior Year.
2 End of Year Balances are from December of the Prior Year.
3 Only projects that are in Rate Base in the year reported are included.
4 Interest relates to refund of facility and one-time payments by generator. For facility costs, pre-in-service date interest is excluded. For one-time costs, pre-in-service and post-in-service interest is included.

Determination of Regulatory Assets/Liabilities and Associated Amortization and Regulatory Debits/Credits

Line

1 Other Regulatory Assets/Liabilities are a component of Rate Base representing costs that are created resulting from the ratemaking
2 actions of regulatory agencies. Pursuant to the Commission's Uniform System of Accounts, these items include amounts recorded
3 in accounts 182.x and 254. This Schedule shall not include any costs recovered through Schedule 12.
4
5 SCE shall include a non-zero amount of Other Regulatory Assets/Liabilities only with Commission
6 approval received subsequent to an SCE Section 205 filing requesting such treatment.
7
8 Amortization and Regulatory Debits/Credits are amounts approved for recovery in this formula transmission rate representing the
9 approved annual recovery of Other Regulatory Assets/Liabilities as an expense item in the Base TRR, consistent
10 with a Commission Order.
11

Line		Prior Year Amount	Calculation or Source
12			
13			
14	Other Regulatory Assets/Liabilities (EOY):	$0	Sum of Column 2 below
15	Other Regulatory Assets/Liabilities (BOY/EOY average):	$0	Avg. of Sum of Cols. 1 and 2 below
16	Amortization and Regulatory Debits/Credits:	$0	Sum of Column 3 below

Line	Description of Issue Resulting in Other Regulatory Asset/Liability	Col 1 Prior Year BOY Other Reg Asset/Liability	Col 2 Prior Year EOY Other Reg Asset/Liability	Col 3 Prior Year Amortization or Regulatory Debit/Credit	Commission Order Granting Approval of Regulatory Liability
17	Issue #1				
18	Issue #2				
19	Issue #3				
20	Totals:	$0	$0	$0	Sum of above

Instructions:

1) Upon Commission approval of recovery of Other Regulatory Assets/Liabilities, Amortization and Regulatory Debits/Credits costs through this formula transmission rate:
   a) Fill in Description for issue in above table.
   b) Enter costs in columns 1-3 in above table for the applicable Prior Year.
2) Add additional lines as necessary for additional issues.

Calculation of the Contribution of CWIP to the Base TRR

1) CWIP Contribution to the Prior Year TRR and True Up TRR

a) CWIP Balances:

Line	Project	Col 1 Prior Year EOY Amount	Col 2 Prior Year Average Amount	Col 3 Forecast Period Amount	Source
1	Tehachapi:	$150,976	$5,894,762	-$150,976	10-CWIP, Lines 13, 14, 80
2	Devers to Colorado River:	$0	$0	$0	10-CWIP, Lines 13, 14, 106
3	South of Kramer:	$4,884,728	$4,594,011	$628,048	10-CWIP, Lines 13, 14, 132
4	West of Devers:	$98,805,812	$80,157,512	$158,421,232	10-CWIP, Lines 13, 14, 158
5	Red Bluff:	$0	$0	$0	10-CWIP, Lines 13, 14, 184
6	Whirlwind Sub Expansion:	$0	$9,253,542	$0	10-CWIP, Lines 27, 28, 210
7	Colorado River Sub Expansion:	$0	$0	$0	10-CWIP, Lines 27, 28, 236
8	Mesa:	$46,788,116	$6,541,655	$110,990,871	10-CWIP, Lines 27, 28, 262
9	Alberhill:	$36,155,803	$2,781,216	$3,359,286	10-CWIP, Lines 27, 28, 288
10	ELM Series Caps:	$34,993,045	$2,691,773	$28,209,776	10-CWIP, Lines 27, 28, 314
11		$0	---	$0	10-CWIP, Lines 27, 28, 340
12	Totals:	$221,778,480	$111,914,471	$301,458,237	Sum of Lines 1 to 11

b) Return:

Line		EOY Amount	Average Amount	Source
13	CWIP Amount:	$221,778,480	$111,914,471	Line 12
14	Cost of Capital Rate:	11.2034%	11.2034%	1-BaseTRR, Line 54
15	Cost of Capital:	$24,846,840	$12,538,281	Line 13 * Line 14

c) Income Taxes

Line		EOY Amount	Average Amount	Source
16	CWIP Amount:	$221,778,480	$111,914,471	Line 12
17	Equity ROR w Preferred Stock ("ER"):	9.1705%	9.1705%	1-BaseTRR, Line 55
18	Composite Tax Rate:	27.9836%	27.9836%	1-BaseTRR, Line 59
19	Income Taxes:	$7,902,888	$3,987,977	Formula on Line 21

20

21 Income Taxes = [(RB * ER) * (CTR/(1 – CTR)], or [(L13 * L17) * (L18 / (1 - L18)]

22 (No "Credits and Other" or "AFUDC" Terms, since these are not related to CWIP)

23

d) ROE Incentives:

Line		Value	Source
24	IREF =	$6,835	15-IncentiveAdder, Line 3

1) Tehachapi

Line		EOY Amount	Average Amount	
25	Tehachapi CWIP Amount:	$150,976	$5,894,762	Line 1
26	ROE Adder %:	1.25%	1.25%	15-IncentiveAdder, Line 5
27	ROE Adder $:	$1,290	$50,365	Formula on Line 32

2) Devers to Colorado River

Line		EOY Amount	Average Amount	
28	DCR CWIP Amount:	$0	$0	Line 2
29	ROE Adder %:	1.00%	1.00%	15-IncentiveAdder, Line 6
30	ROE Adder $:	$0	$0	Formula on Line 32

31

32 ROE Adder $ = (Project CWIP Amount/$1,000,000) * IREF * (ROE Adder % / 1%)

e) Total of Return, Income Taxes, and ROE Incentives contribution to PYTRR and True Up TRR

Line		PYTRR Amount	True Up TRR Amount	Source
33	Return:	$24,846,840	$12,538,281	Line 15
34	Income Taxes:	$7,902,888	$3,987,977	Line 19
35	ROE Adder Tehachapi:	$1,290	$50,365	Line 27
36	ROE Adder DCR:	$0	$0	Line 30
37	FF&U:	$380,347	$152,599	Note 1
38	Total:	$33,131,365	$16,729,223	Sum Lines 33 to 37

f) Contribution from each Project to the Prior Year TRR and True Up TRR

1) Contribution to the Prior Year TRR

	Project	Col 1 Cost of Capital	Col 2 Income Taxes	Col 3 ROE Adder	Col 4 FF&U	Col 5 = Sum C1 to C4 Total	Source
39	Tehachapi:	$16,915	$5,380	$1,290	$274	$23,858	Note 2
40	Devers to Colorado River:	$0	$0	$0	$0	$0	Note 2
41	South of Kramer:	$547,258	$174,063	$0	$8,377	$729,698	Note 2
42	West of Devers:	$11,069,659	$3,520,861	$0	$169,444	$14,759,964	Note 2
43	Red Bluff:	$0	$0	$0	$0	$0	Note 2
44	Whirlwind Sub Expansion:	$0	$0	$0	$0	$0	Note 2
45	Colorado River Sub Expansion:	$0	$0	$0	$0	$0	Note 2
46	Mesa	$5,241,883	$1,667,255	$0	$80,238	$6,989,376	Note 2
47	Alberhill	$4,050,697	$1,288,381	$0	$62,004	$5,401,083	Note 2
48	ELM Series Caps	$3,920,428	$1,246,947	$0	$60,010	$5,227,386	Note 2
49		---	---	---	---	---	Note 2
50	Totals:	$24,846,840	$7,902,888	$1,290	$380,347	$33,131,365	Sum L 39 to L 49

2) Contribution to the True Up TRR

	Project	Col 1 Cost of Capital	Col 2 Income Taxes	Col 3 ROE Adder	Col 4 FF&U	Col 5 = Sum C1 to C4 Total	Source
51	Tehachapi:	$660,417	$210,055	$50,365	$10,694	$931,531	Note 3
52	Devers to Colorado River:	$0	$0	$0	$0	$0	Note 3
53	South of Kramer:	$514,688	$163,704	$0	$7,878	$686,270	Note 3
54	West of Devers:	$8,980,406	$2,856,345	$0	$137,464	$11,974,215	Note 3
55	Red Bluff:	$0	$0	$0	$0	$0	Note 3
56	Whirlwind Sub Expansion:	$1,036,716	$329,742	$0	$15,869	$1,382,327	Note 3
57	Colorado River Sub Expansion:	$0	$0	$0	$0	$0	Note 3
58	Mesa	$732,891	$233,106	$0	$11,218	$977,216	Note 3
59	Alberhill	$311,592	$99,106	$0	$4,770	$415,468	Note 3
60	ELM Series Caps	$301,571	$95,919	$0	$4,616	$402,107	Note 3
61		---	---	---	---	---	Note 3
62	Totals:	$12,538,281	$3,987,977	$50,365	$192,509	$16,769,133	Sum of L 51 to 61

2) Contribution from the Incremental Forecast Period TRR

a) Total of all CWIP projects

		Value	Source
63	Forecast Period Incremental CWIP:	$301,458,237	Line 12, Col 3
64	AFCRCWIP:	14.767%	2-IFPTRR, Line 16
65	CWIP component of IFPTRR without FF&U:	$44,515,929	Line 63 * Line 64
66	FF&U:	$516,977	Line 65 * (28-FFU, L5 FF Factor + U Factor)
67	CWIP component of IFPTRR including FF&U:	$45,032,906	Line 65 + Line 66

b) Individual Project Contribution

	Project	Amount wo FF&U	Amount with FF&U	Source
68	Tehachapi:	-$22,294	-$22,553	Note 4
69	Devers to Colorado River:	$0	$0	Note 4
70	South of Kramer:	$92,743	$93,820	Note 4
71	West of Devers:	$23,393,849	$23,665,528	Note 4
72	Red Bluff:	$0	$0	Note 4
73	Whirlwind Sub Expansion:	$0	$0	Note 4
74	Colorado River Sub Expansion:	$0	$0	Note 4
75	Mesa	$16,389,871	$16,580,212	Note 4
76	Alberhill	$496,061	$501,822	Note 4
77	ELM Series Caps	$4,165,699	$4,214,077	Note 4
78		---	---	Note 4
79	Totals:	$44,515,929	$45,032,906	Sum of Lines 68 to 78

3) Total Contribution of CWIP to the Retail and Wholesale Base TRRs:

a) Total of all CWIP projects

		Value	Source
80	PY Total Return, Taxes, Incentive:	$32,751,017	Sum Line 33 to 36
81	CWIP component of IFPTRR wo FF&U:	$44,515,929	Line 65
82	Total without FF&U:	$77,266,947	Line 80 + Line 81
83	FF Factor:	0.9206%	28-FFU, Line 5
84	U Factor:	0.2408%	28-FFU, Line 5
85	Franchise Fees Amount:	$711,296	Line 82 * Line 83
86	Uncollectibles Amount:	$186,028	Line 82 * Line 84
87	Total Contribution of CWIP to Retail Base TRR:	$78,164,271	Line 82 + Line 85 + Line 86
88	Total Contribution of CWIP to Wholesale Base TRR:	$77,978,243	Line 82 + Line 85

b) Individual CWIP Project Contribution to the Retail Base TRR

		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF&U	Col 4 Total	Source
89	Tehachapi:	$23,584	-$22,294	$15	$1,305	Note 5
90	Devers to Colorado River:	$0	$0	$0	$0	Note 5
91	South of Kramer:	$721,321	$92,743	$9,454	$823,518	Note 5
92	West of Devers:	$14,590,520	$23,393,849	$441,124	$38,425,493	Note 5
93	Red Bluff:	$0	$0	$0	$0	Note 5
94	Whirlwind Sub Expansion:	$0	$0	$0	$0	Note 5
95	Colorado River Sub Expansion:	$0	$0	$0	$0	Note 5
96	Mesa	$6,909,138	$16,389,871	$270,578	$23,569,587	Note 5
97	Alberhill	$5,339,078	$496,061	$67,765	$5,902,905	Note 5
98	ELM Series Caps	$5,167,376	$4,165,699	$108,388	$9,441,463	Note 5
99		---	---	---	---	Note 5
100	Totals:	$32,751,017	$44,515,929	$897,324	$78,164,271	

c) Individual CWIP Project Contribution to the Wholesale Base TRR

		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF	Col 4 Total	Source
101	Tehachapi:	$23,584	-$22,294	$12	$1,302	Note 6
102	Devers to Colorado River:	$0	$0	$0	$0	Note 6
103	South of Kramer:	$721,321	$92,743	$7,494	$821,558	Note 6
104	West of Devers:	$14,590,520	$23,393,849	$349,673	$38,334,042	Note 6
105	Red Bluff:	$0	$0	$0	$0	Note 6
106	Whirlwind Sub Expansion:	$0	$0	$0	$0	Note 6
107	Colorado River Sub Expansion:	$0	$0	$0	$0	Note 6
108	Mesa	$6,909,138	$16,389,871	$214,484	$23,513,493	Note 6
109	Alberhill	$5,339,078	$496,061	$53,717	$5,888,856	Note 6
110	ELM Series Caps	$5,167,376	$4,165,699	$85,917	$9,418,992	Note 6
111		---	---	---	---	Note 6
112	Totals:	$32,751,017	$44,515,929	$711,296	$77,978,243	

Notes:

1) (Sum Lines 33 to 36) * (FF + U Factors from 28-FFU) for Prior Year TRR
(Sum Lines 33 to 36) * (FF Factor from 28-FFU) for True Up TRR
2) Project Cost of capital is a fraction of total Cost of Capital on Line 15 based on fraction of project CWIP Balances on Lines 1 to 12, Col 1.
Project Income Taxes is a fraction of total Income on Line 19 based on fraction of project CWIP Balances on Lines 1 to 12, Col 1.
ROE Adder is from Lines 35 and 36. FF&U Expenses are based on FF&U Factors on 28-FFU.
3) Project Cost of capital is a fraction of total Cost of Capital on Line 15 based on fraction of project CWIP Balances on Lines 1 to 12, Col 2.
Project Income Taxes is a fraction of total Income on Line 19 based on fraction of project CWIP Balances on Lines 1 to 12, Col 2.
ROE Adder is from Lines 35 and 36. FF&U Expenses are based on FF&U Factors on 28-FFU.
4) Project contribution to total IFPTRR is based on fraction of Forecast Period CWIP Balances on Lines 1 to 12, Col 3.
5) Column 1 is from Lines 39 to 49, Sum of Column 1-3 (no FF&U).
Column 2 is from Lines 68 to 78 (no FF&U).
Column 3 is the product of (C1 + C2) and the sum of FF and U factors (28-FFU, L5)
6) Same as Note 5 except no Uncollectibles Expense in Column 3.

Calculation of Wholesale Difference to the Base TRR

Inputs are shaded yellow

The Wholesale Difference to the Base TRR represents the amount by which the Wholesale Base TRR differs as compared to the Retail Base TRR. This difference is attributable to differences in the following six items, as approved by Commission Order 86 FERC ¶ 63,014 in Docket No. ER97-2355.

These six items may affect the Base TRR by affecting Rate Base, or affecting an annual expense (amortization). If the annual amortization affects Income Taxes, there is an additional annual Income Tax Effect. The table summarizes these impacts for each item:

Line		Rate Base Difference	Expense (Amortization) Difference	Expense Tax Impact
1	a) Depreciation	Yes	Yes	No
2	b) Taxes Deferred -Make Up Adjustment (South Georgia)	Yes	Yes	Yes
3	c) Excess Deferred Taxes	Yes	Yes	Yes
4	d) Taxes Deferred - Acct. 282 ACRS/MACRS	Yes	Yes	No
5	e) Uncollectibles Expense	No	Yes	No
6	f) EPRI and EEI Dues	No	Yes	No

1) Calculation of Wholesale Rate Base Difference and Wholesale Rate Base Adjustment

a) Quantification of the Initial 2010 Wholesale Rate Base Difference and annual change

The difference between Retail and Wholesale Rate Base is attributable to the following four items, with the Initial Prior Year 2010 Rate Base differences and annual changes as follows:

		Data Source		Col 1 2010 Rate Base Difference (Wholesale less Retail)	Col 2 Annual Change (Amortization)
7	1) Accumulated Depreciation	Fixed values		$31,556,000	-$2,176,300
8	2) Taxes Deferred - Make Up Adjustment	Fixed values		-$35,044,000	$2,503,000
9	3) Excess Deferred Taxes	Fixed values		-$624,650	$43,100
10	4) Taxes Deferred - Acct. 282 ACRS/MACRS	Fixed values		-$7,410,000	$511,200
11			Totals:	-$11,522,650	$881,000

b) Quantification of the Wholesale Rate Base Adjustment

The Wholesale Rate Base Adjustment represents the impact on the Wholesale Base TRR relative to the Retail Base TRR of the Wholesale Rate Base Difference for the Prior Year.

		Data Source	Value	Notes/Instructions
12	Fixed Charge Rate	2-IFPTRR Line 16	14.77%	1
13	Prior Year		2017	2
14	Wholesale Rate Base Difference for Prior Year		-$5,355,650	3
15	Wholesale Rate Base Adjustment	Line 14 * Line 12	-$790,862	

2) Calculation of Wholesale Expense Difference

The annual Wholesale Expense Difference impact is the negative of amounts stated in Lines 7 to 10 above, Column 2. It represents the effect on expenses (Wholesale less Retail) of amortizing the associated balances each year. If an annual amortization amount affects Income Taxes, the expense difference must be grossed up for income taxes.

a) Calculation of the Wholesale South Georgia Income Tax Adjustment to the TRR

		Source	Value
16	South Georgia Amortization	Line 8	$2,503,000
17	Composite Tax Rate ("CTR")	1-BaseTRR L 59	27.984%
18	Tax Gross Up Factor	(1/(1-CTR))	1.3886
19	Wholesale South Georgia		
20	Income Tax Adjustment to the TRR:	- Line 16 * Line 18	-$3,475,597.23

b) Calculation of "Excess Deferred Taxes" Grossed Up for Income Taxes

		Source	Value
21	Annual Amort. of "Excess Deferred Taxes":	Line 9	$43,100
22	Tax Gross Up Factor	Line 18	1.3886
23	Excess Deferred Taxes Grossed Up for Income Taxes:	- Line 21 * Line 22	-$59,847
24			

25	**c) Calculation of EPRI and EEI Dues Exclusion**			
26		**Source**		**Notes/Instructions**
27	EPRI Dues	SCE Records	$200,769	Note 5
28	EEI Dues	SCE Records	$1,529,649	Note 5
29	Sum of EPRI and EEI Dues	Line 27 + 28	$1,730,418	
30	Transmission Wages and Salaries Allocation Factor	27-Allocators, Line 9	6.0143%	
31	EPRI and EEI Dues Exclusion	Line 29 * 30	$104,073	
	d) Total Expense Difference			**Notes/Instructions**
32	1) Wholesale Depreciation Difference	- Line 7, Col. 2	$2,176,300	
33	2) Taxes Deferred - Make Up Adjustment	Line 20	-$3,475,597	
34	3) Excess Deferred Taxes	Line 23	-$59,847	
35	4) Taxes Deferred - Acct. 282 ACRS/MACRS	- Line 10, Col. 2	-$511,200	
36	5) EPRI and EEI Dues Exclusion	- Line 31	-$104,073	
37	6) Additional Expense Difference		$0	Note 6
38		Total Expense Difference:	-$1,974,418	

	3) Calculation of the Wholesale Difference to the Base TRR			
		Source	**Value**	
39	Wholesale Rate Base Adjustment	Line 15	-$790,862	
40	Expense Difference	Line 38	-$1,974,418	
41	Uncollectibles Expense -- Prior Year TRR	- 1-Base TRR, L 80	-$2,994,074	
42	Uncollectibles Expense -- IFPTRR	- 2-IFPTRR, L 80	-$315,909	
43	Subtotal:	Sum Line 39 to Line 42	-$6,075,263	
44	Franchise Fee Exclusion		-$25,456	Note 4
45	Wholesale Difference to the Base TRR:	Line 43 + Line 44	-$6,100,719	

Notes/Instructions:
1) Fixed Charge Rate of capital and income tax costs associated with $1 of Rate Base is defined elsewhere in this formula as "AFCRCWIP".
2) Input Prior Year for this Informational Filing in Line 13.
3) Calculation: (Line 11, Col 1) + ((Line 11, Col 2) * (Line 13 - 2010)).
4) Franchise Fee Exclusion is equal to the Franchise Fee Factor on the 28-FFU Line 5 times Line 39 + 40.
5) Only exclude if not already excluded in Schedule 20.
6) If appropriate, additional expenses may be excluded from the Wholesale Base TRR

Income Tax Rates

1) Federal Income Tax rate Inputs are shaded yellow

Line	Rate Year	Federal Income Tax Rate ("FITR")	Source
1	2019	21.00%	Note 1, Note 4
2			
3	**2) Composite State Income Tax Rate**		
4			
5			
6			
7	Rate Year	State Income Tax Rate ("CSITR")	Source
8	2019	8.8400%	Note 2
9			
10			
11			

Line	3) Capitalized Overhead portion of Electric Payroll Tax Expense	Amount
13		
14	Total Electric Payroll Tax Expense (From 1-BaseTRR, Line 31)	$117,049,541
15	Capitalization Rate (Note 3)	39.8%
16	Capitalized Overhead portion of Electric Payroll Tax Expense (Line 14 * Line 15)	$46,585,717
17	Non-Capitalized Overhead portion of Electric Payroll Tax Expense (Line 14 - Line 16)	$70,463,824

Notes:

1) Federal Source Statute: Internal Revenue Code § 11.b

2) California State Source Statue:
California Rev. & Tax. Cd. § 23151

3) Capitalization Rate approved in: CPUC D. 15-11-021
For the following Prior Years: 2015-2017

4) In the event that either the Federal or State Income Tax Rate applicable to the Rate Year differs from that in effect during the Prior Year, the True Up TRR for the Prior Year will be calculated utilizing the same Formula Rate Spreadsheet except for the Income Tax rate(s). The difference between the True Up TRR calculated in such workpaper using the Income Tax Rates that were in effect during the Prior Year and the True Up TRR otherwise calculated by this formula shall be entered as a One Time Adjustment on Schedule 3, ensuring that the Formula Spreadsheet correctly calculates the True Up TRR for the Prior Year to be based on the Income Tax Rate(s) that were in effect during that year. For the Prior Years of 2016 and 2017, both of which will have Income Tax Rates that differ between the Prior Year and the Rate Year due to the passage of the 2017 Tax Cuts and Jobs Act, this provision will be implemented as part of the Section 6 of the Formula Rate Protocols, which will calculate the True Up TRR for those years based on a Federal Income Tax Rate of 35%.

Calculation of Allocation Factors

Inputs are shaded yellow

1) Calculation of Transmission Wages and Salaries Allocation Factor

Line		Notes	FERC Form 1 Reference or Instruction	Prior Year Value
1	ISO Transmission Wages and Salaries		19-OandM Line 91, Col. 7	$35,938,613
2	Total Wages and Salaries		FF1 354.28b	$749,285,680
3	Less Total A&G Wages and Salaries		FF1 354.27b	$210,410,528
4	Total Wages and Salaries wo A&G		Line 2 - Line 3	$538,875,152
5	Total NOIC (Non-Officer Incentive Compensation)		20-AandG, Note 2	$88,782,682
6	Less A&G NOIC		20-AandG, Note 2	$30,108,715
7	NOIC wo A&G NOIC		Line 5 - Line 6	$58,673,968
8	Total non-A&G W&S with NOIC		Line 4 + Line 7	$597,549,120
9	Transmission Wages and Salary Allocation Factor		Line 1 / Line 8	6.0143%
10				
11	**2) Calculation of Transmission Plant Allocation Factor**			
12			**FERC Form 1 Reference**	**Prior Year**
13		**Notes**	**or Instruction**	**Value**
14	Transmission Plant - ISO		7-PlantStudy, Line 21	$8,573,445,553
15	Distribution Plant - ISO		7-PlantStudy, Line 30	$0
16	Total Electric Miscellaneous Intangible Plant		6-PlantInService, Line 21, C2	$1,324,870,316
17	Electric Miscellaneous Intangible Plant - ISO		Line 16 * Line 9	$79,682,156
18	Total General Plant		6-PlantInService, Line 21, C1	$3,102,162,333
19	General Plant - ISO		Line 18 * Line 9	$186,574,475
20	Total Plant In Service		FF1 207.104g	$46,164,121,713
21				
22	Transmission Plant Allocation Factor		(L14 + L15 + L17 + L19) / L20	19.1484%
23				

Line		Values	Notes	Applied to Accounts
24	**3) Schedule 19 "Percent ISO" Allocation Factors (Input values are from SCE Records)**			
25				
26	a) Line Miles	**Values**	**Notes**	**Applied to Accounts**
27	ISO Line Miles	5,683		563 - Overhead Line Expenses - Allocated
28	Non-ISO Line Miles	6,473		567 - Line Rents - Allocated
29	Total Line Miles	12,156	= L27 + L28	571 - Maintenance of Overhead Lines - Allocated
30	Line Miles Percent ISO	46.8%	= L27 / L29	
31				
32	b) Underground Line Miles	**Values**	**Notes**	**Applied to Accounts**
33	ISO Underground Line Miles	5		564 - Underground Line Expense
34	Non-ISO Underground Line Miles	355		572 - Maintenance of Underground Transmission Lines
35	Total Undergound Line Miles	360	= L33 + L34	
36	Underground Line Miles Percent ISO	1.4%	= L33 / L35	
37				
38	c) Circuit Breakers	**Values**	**Notes**	**Applied to Accounts**
39	ISO Circuit Breakers	1,205		All Other Non 0% or 100% Transmission O&M Accounts
40	Non-ISO Breakers	2,083		
41	Total Circuit Breakers	3,288	= L39 + L40	
42	Circuit Breakers Percent ISO	36.6%	= L39 / L41	
43				
44	d) Distribution Circuit Breakers	**Values**	**Notes**	**Applied to Accounts**
45	ISO Distribution Circuit Breakers	0		582 - Station Expenses
46	Non-ISO Distribution Circuit Breakers	8,853		590 - Maintenance Supervision and Engineering
47	Total Distribution Circuit Breakers	8,853	= L45 + L46	591 - Maintenance of Structures
48	Distribution Circuit Breakers Percent ISO	0.0%	= L45 / L47	592 - Maintenance of Station Equipment

Franchise Fees and Uncollectibles Expense Factors

1) Approved Franchise Fee Factor(s)

Inputs are shaded yellow

Line	From	To	Days in Prior Year	FF Factor	Reference
1	2017	Present	365	0.92057%	Schedule 28 - Workpaper Line 3
2					

2) Approved Uncollectibles Expense Factor(s)

Line	From	To	Days in Prior Year	U Factor	Reference
3	2017	Present	365	0.24076%	Schedule 28 - Workpaper Line 4
4					

3) FF and U Factors

Line	Prior Year	FF Factor	U Factor	Notes
5	2017	0.92057%	0.24076%	Calculated according to Instruction 3

Notes:
1) Franchise Fees represent payments that SCE makes to municipal entities for the right to locate facilities within the municipality.

Instructions:
1) Enter Franchise Fee and Uncollectibles Factors as approved by the California Public Utilities Commission ("CPUC") in modules 1 and 2 above pursuant to Instruction 2. If approved factors changed during Prior Year, enter both, and note period of time for which each applies in "From" and "To" columns, and number of days each was in effect during the Prior Year in "Days in Prior Year" Column.
2) Franchise Fees Factor is calculated from CPUC Decision by dividing adopted Franchise Fees by Total Operating Revenues less Franchise Fees. Uncollectibles Factor is calculated by dividing adopted Uncollectibles expense by Total Operating revenues less Uncollectibles Expense. Resulting FF & U Factors represent factors that, when applied to TRR without FF and U will correctly determine FF and U expense.
3) Calculate in module 3 the weighted average FF and U factors from the factors in modules 1 and 2 based on the number of days each FF and U factor was in effect during the Prior Year at issue.

	Percent	Calculation
Prior Year FF Factor:	0.92057%	((L1 FF Factor * L1 Days) + (L2 FF Factor * L2 Days))/(L1+L2 Days)
Prior Year U Factor:	0.24076%	((L3 U Factor * L3 Days) + (L4 U Factor * L4 Days))/(L3+L4 Days)

CALCULATION OF SCE WHOLESALE HIGH AND LOW VOLTAGE TRRS

Inputs are shaded yellow

Line	TRR Values		Notes	Source	
1	$1,322,194,021	= Wholesale Base TRR		1-BaseTRR, Line 89	
2	-$72,958,322	= Total Wholesale TRBAA	Note 1	2019 TRBAA	ER19-220
3	-$72,644,844	= HV Wholesale TRBAA		2019 TRBAA	ER19-220
4	-$313,478	= LV Wholesale TRBAA		2019 TRBAA	ER19-220
5	-$9,957,569	= Total Standby Transmission Revenues	Note 2	SCE Retail Standby Rate Revenue	
6	96.9981%	= HV Allocation Factor		31-HVLV, Line 37	
7	3.0019%	= LV Allocation Factor		31-HVLV, Line 37	

Calculation of Total High Voltage and Low Voltage components of Wholesale TRR

		Col 1	Col 2	Col 3	
		TOTAL	High Voltage	Low Voltage	Source
8	**Wholesale Base TRR:**	$1,322,194,021	$1,282,502,985	$39,691,036	See Note 3
9	**CWIP Component of Wholesale Base TRR:**	$77,978,243	$77,978,243	$0	See Note 4
10	**Non-CWIP Component of Wholesale Base TRR:**	$1,244,215,779	$1,204,524,742	$39,691,036	See Note 5
11	**Wholesale TRBAA:**	-$72,958,322	-$72,644,844	-$313,478	Lines 2 to 4
12	**Less Standby Transmission Revenues:**	-$9,957,569	-$9,658,652	-$298,917	See Note 6
13	**Components of Wholesale Transmission Revenue Requirement:**	$1,239,278,131	$1,200,199,489	$39,078,641	Sum of Lines 8, 11, and 12

Notes:

1) TRBAA is "Transmission Revenue Balancing Account Adjustment". The TRBAA is determined pursuant to SCE's Transmission Owner Tariff and may be revised each January 1, upon commission acceptance of a revised TRBAA amount, or upon the date the Commission orders.

2) From 33-RetailRates. See Line: Line 17, column 3

3) Column 1 is from Line 1.
   Column 2 equals Column 1 * Line 6.
   Column 3 equals Column 1 * Line 7.

4) From 24-CWIPTRR, Line 88. All High Voltage.

5) Line 8 - Line 9

6) Column 1 is from Line 5.
   Column 2 equals Column 1 * Line 6.
   Column 3 equals Column 1 * Line 7.

Calculation of SCE Wholesale Rates (See Note 1)

SCE's wholesale rates are as follows:

1) Low Voltage Access Charge
2) High Voltage Utility-Specific Rate
3) HV Existing Contracts Access Charge

Calculation of Low Voltage Access Charge:

Line				Source
1	LV TRR =	$39,078,641		29-WholesaleTRRs, Line 13, C3
2	Gross Load =	86,703,491	MWh	32-Gross Load, Line 4
3	Low Voltage Access Charge =	$0.00045	per kWh	Line 1 / (Line 2 * 1000)

Calculation of High Voltage Utility Specific Rate:
(used by ISO in billing of ISO TAC)

				Source
4	SCE HV TRR =	$1,200,199,489		29-WholesaleTRRs, Line 13, C2
5	Gross Load =	86,703,491	MWh	32-Gross Load, Line 4
6	High Voltage Utility-Specific Rate =	$0.0138426	per kWh	Line 4 / (Line 5 * 1000)

Calculation of High Voltage Existing Contracts Access Charge:

				Source
7	HV Wholesale TRR =	$1,200,199,489		29-WholesaleTRRs, Line 13, C2
8	Sum of Monthly Peak Demands:	162,442	MW	32-Gross Load, Line 5
9	HV Existing Contracts Access Charge:	$7.39	per kW	Line 7 / (Line 8 * 1000)

Notes:
1) SCE's wholesale rates are subject to revision upon acceptance by the Commission of a revised TRBAA amount. See Note 1 on 29-WholesaleTRRs.

Derivation of High Voltage and Low Voltage Gross Plant Percentages
Determination of HV and LV Gross Plant Percentages for ISO Transmission Plant in accordance with ISO Tariff Appendix F, Schedule 3, Section 12. Input cells are shaded yellow

HV and LV Components of Total ISO Plant on Lines 2, 3, 7, 8, and 9 are from the Plant Study, performed pursuant to Section 9 of Appendix IX:

Line	A) Total ISO Plant from Prior Year Classification of Facility:	Total ISO Gross Plant	Land	Structures	HV Land	LV Land	HV Structures	LV Structures	HV/LV Transformers
1	**Lines:**								
2	HV Transmission Lines	$4,456,571,807	$207,303,577	$4,249,268,230	$207,303,577	$0	$4,249,268,230	$0	$0
3	LV Transmission Lines	$97,777,323	$5,523,117	$92,254,206	$0	$5,523,117	$0	$92,254,206	$0
4	**Total Transmission Lines (L2 + L3):**	$4,554,349,130	$212,826,694	$4,341,522,436	$207,303,577	$5,523,117	$4,249,268,230	$92,254,206	$0
5									
6	**Substations:**								
7	HV Substations (>= 200 kV)	$3,527,998,671	$39,632,449	$3,488,366,223	$39,632,449	$0	$3,488,366,223	$0	$0
8	Straddle Subs (Cross 200 kV boundary):	449,562,934	$190,905	$449,372,030	$110,505	$80,400	$267,329,959	$128,270,187	$53,771,884
9	LV Substations (Less Than 200kV)	41,534,818	$127,274	$41,407,544	$0	$127,274	$0	$41,407,544	$0
10	**Total all Substations (L7 + L8 + L9)**	$4,019,096,424	$39,950,627	$3,979,145,797	$39,742,953	$207,674	$3,755,696,182	$169,677,731	$53,771,884
11									
12	**Total Lines and Substations**	$8,573,445,553	$252,777,321	$8,320,668,232	$247,046,530	$5,730,791	$8,004,964,412	$261,931,936	$53,771,884
13									
14									

Line		High Voltage	Low Voltage	Total	Notes:
15	Gross Plant that can directly be determined to be HV or LV:				
18	Land	$247,046,530	$5,730,791	$252,777,321	From above Line 12
19	Structures	$8,004,964,412	$261,931,936	$8,266,896,348	From above Line 12
20	Total Determined HV/LV:	$8,252,010,942	$267,662,727	$8,519,673,669	Sum of lines 18 and 19
21	Gross Plant Percentages (Prior Year):	96.858%	3.142%		Percent of Total
22					
23	Straddling Transformers	$52,082,532	$1,689,352	$53,771,884	Straddling Transformers split by Gross Plant Percentages on Line 21
24	Abandoned Plant (BOY)	$0	$0	$0	Total: 12-Abandoned Plant Line 2, HV: 12-Abandoned Plant Line 5, LV = Total - HV
25	Total HV and LV Gross Plant for Prior Year	$8,304,093,474	$269,352,079	$8,573,445,553	Line 20 + Line 23 + Line 24
26					
27					

28 **B) Gross Plant Percentage for the Rate Year:**

Line		High Voltage	Low Voltage	Total	Notes:
32	Total HV and LV Gross Plant for Prior Year	$8,304,093,474	$269,352,079	$8,573,445,553	Line 25
33	In Service Additions in Rate Year:	$508,628,194	$12,714,512	$521,342,706	13-Month Average: 16-PlantAdditions, Line 25, Cols 7 (for Total) and 12 (for LV). HV = C7 - C12.
34	CWIP in Rate Year	$301,458,237	$0	$301,458,237	13 Month Average: 10-CWIP, Line 54, Col. 8
35	Total HV and LV Gross Plant for Rate Year	$9,114,179,904	$282,066,591	$9,396,246,495	Line 32 + Line 33 + Line 34
36					
37	HV and LV Gross Plant Percentages:	96.998%	3.002%		Percent of Total on Line 35
38	(HV Allocation Factor and				
39	LV Allocation Factor)				

Calculation of Forecast Gross Load

Line		MWh	Calculation	Source
1	SCE Retail Sales at ISO Grid level:	86,680,005		Note 1
2	Pump Load forecast:	14,868		Note 2
3	Pump Load True-Up:	8,618		Note 4
4	Forecast Gross Load:	86,703,491	Line 1 + Line 2 + Line 3	Sum of above
5	Forecast 12-CP Retail Load:	162,442		Note 1

Notes:
1) Latest SCE approved sales forecast as of April 15 of each year.
2) SCE pump load forecast as of April 15 of each year.
3) The load forecast used in Schedule 32 shall be for the calendar year in which the rates are to be in effect.
4) The Pump Load True-Up value is equal to actual recorded less forecast Pump Load for the Prior Year.

Calculation of SCE Retail Transmission Rates

		Source	
Retail Base TRR:	1,328,294,741	1-BaseTRR WS, Line 86	**Input cells are shaded yellow**

1) Derivation of "Total Demand Rate" and "Total Energy Rate":

Line	CPUC Rate Group	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
		Note 1		Note 2	Note 3	Note 4	Note 5	Note 6	Note 7		Note 8	Note 8	Note 8		
				Sales Forecast Billing Determinants:											
			= Retail Base TRR * Line1:Col1	Sales Forecast (Not Including Backup)	Sales Forecast (Backup)	NEM Adjustment	Applies to supplemental kW demand charges	Applies to contracted standby kW demand charges	= (Line1:Col3 + Line1:Col4) - Line1:Col5	= Line1:Col2 / (Line1:Col8*10^6)	= Line1:Col2 / ((Line1:Col6 + Line1:Col7)*10^3)	Recorded Billing Determinants: to be applied to the Supplemental kW demand charges, and the Contracted Standby kW demand charges			
Line	**CPUC Rate Group**	**12-CP factors**	**Total Allocated costs**	**GWh**	**Backup GWh**	**NEM GWh**	**Maximum demand - MW**	**Standby demand - MW**	**Billing Determinants with NEM Adjustment**	**Total energy rate - $/kWh**	**Total demand rate - $/kW-month**	**GWh**	**Maximum demand - MW**	**Standby demand - MW**	**Notes**
1a	Domestic	41.72%	$554,108,197	28,443		1431	0	0	27,012	$0.02051					
1b	TOU-GS-1	7.77%	$103,239,014	5,911		11	0	0	5,900	$0.01750		5,942	29,137	0	
1b2	TOU-GS-1 continued			0					0		$3.57	$103,983,857	$3.57		Notes 9,10
1c	TC-1	0.05%	$648,496	58			0		58	$0.01125					
1d	TOU-GS-2	16.51%	$219,332,017	13,100		61	44,897	36	13,039		$4.88				
1e	TOU-GS-3	9.11%	$121,020,316	7,840		68	22,683	70	7,772		$5.32				
1f	TOU-8-SEC	8.79%	$116,710,841	8,055		37	20,531		8,018		$5.68				
1g	TOU-8-PRI	5.83%	$77,482,171	5,509		23	12,817		5,486		$6.05				
1h	TOU-8-SUB	6.32%	$83,981,663	5,868		0	11,894		5,868		$7.06				
1i	TOU-8-Standby-SEC	0.09%	$1,250,317	113	97		325	285	210		$2.05				
1j	TOU-8-Standby-PRI	0.20%	$2,698,124	534	243		1,310	1,373	778		$1.01				
1k	TOU-8-Standby-SUB	0.42%	$5,516,457	1,672	560		3,309	8,394	2,231		$0.47				
1l	TOU-PA-2	1.57%	$20,845,998	1,816		6	8,121	1	1,810		$2.57				
1m	TOU-PA-3	1.19%	$15,744,938	1,454		16	4,933	8	1,438		$3.19				
1n	Street Lighting	0.43%	$5,716,191	698			0		698	$0.00819					
1o	---								0						
2	Totals:	100.00%	$1,328,294,741	81,070	900	1,653	130,819	10,166	80,317						
3															
4															

5 **2) Determination of Demand Rates for Large Power (TOU-8) Rate Groups**

Line	CPUC Rate Group	Col 1	Col 2	Col 3	Col 4	CPUC Rate Group	Col 5	Col 6	Col 7	Col 8
7		from Line1:Col2	from Line1:Col7	= Col1 / Col2 / 10^3				from Line1:Col2	Note 11	= Col 6 / (Col 7 * 10^3)
8										
9	**CPUC Rate Group**	**Standby Allocated costs**	**Standby Demand - MW**	**Contracted Standby Demand Charge $/kW**		**CPUC Rate Group**		**Non-Standby Allocated Costs**	**Sum of Standby and Non-Standby Demand**	**Supplemental kW demand Charge $/kW**
9a	TOU-8-Standby-SEC	$1,250,317	285	$4.39		TOU-8-SEC		$116,710,841	20,856	5.60
9b	TOU-8-Standby-PRI	$2,698,124	1,373	$1.97		TOU-8-PRI		$77,482,171	14,126	5.48
9c	TOU-8-Standby-SUB	$5,516,457	8,394	$0.66		TOU-8-SUB		$83,981,663	15,203	5.52
9d	---					---				
10										

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
11	**3) End-User Transmission Rates**											
12		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
13		= Col 2 + Col 3	= Line1:Col2 - Line16:Col3	= Line16:Col7 * Line1:Col7 *10^3		= Line16:Col2 / (Line1:Col8 * 10^6)	= Line16:Col2 / Line1:Col6 / 10^3	from Line9:Col3	= Line16:Col6 * 0.746	= Line16:Col7 * 0.746		= Line16:Col2 / (Line1:Col8 * 10^6)
14			Note 12				Note 13	Note 14				
15	**CPUC Rate Group**	**Total Revenues**	**Revenue associated with Supplemental Demand or Energy**	**Standby Demand Revenue**		**Energy Charge - $/kWh**	**Supplemental Demand Charge - $/kW-month**	**Contracted standby kW demand Charge - $/kW-month**	**Supplemental Demand Charge - $/HP-month**	**Contracted standby kW demand Charge - $/HP-month**	**Notes**	Transportation Electrification (TE) Energy Charge - $/kWh
16a	Domestic	$554,108,197	$554,108,197			$0.02051						
16b	TOU-GS-1	$103,239,014	$103,239,014	$0		$0.01750	$3.57	$3.57			Note 15	0.01750
16c	TC-1	$648,496	$648,496			$0.01125						
16d	TOU-GS-2	$219,332,017	$219,174,022	$157,995			$4.88	$4.39			Note 16	0.01633
16e	TOU-GS-3	$121,020,316	$120,713,103	$307,213			$5.32	$4.39				0.01633
16f	TOU-8-SEC	$114,893,480	$114,893,480				$5.60					0.01433
16g	TOU-8-PRI	$70,298,127	$70,298,127				$5.48					0.01282
16h	TOU-8-SUB	$65,703,494	$65,703,494				$5.52					0.01120
16i	TOU-8-Standby-SEC	$3,067,677	$1,817,361	$1,250,317			$5.60	$4.39				
16j	TOU-8-Standby-PRI	$9,882,168	$7,184,044	$2,698,124			$5.48	$1.97				
16k	TOU-8-Standby-SUB	$23,794,626	$18,278,169	$5,516,457			$5.52	$0.66				
16l	TOU-PA-2	$20,845,998	$20,844,674	$1,324			$2.57	$2.57	$1.91	$1.91	Note 17	
16m	TOU-PA-3	$15,744,938	$15,718,799	$26,140			$3.19	$3.19				
16n	Street Lighting	$5,716,191	$5,716,191			$0.00819						
16o	---											
17	Totals:	$1,328,294,741	$1,318,337,171	$9,957,569								
18												

19 **Notes:**

1) See Col 9 of Lines 35a, 35b, 35c, etc.
2) Sales forecast in total Giga-watt hours usage, represents the customers' total annual GWh usage. Based on same forecast as Gross Load forecast in Schedule 32, Line 1, but at customer meter level. Does not include Backup GWh included in Column 4 (the sum of Column 3 and 4 equals total Sales Forecast).
3) Backup GWh represents the amount of electric service that is provided by SCE to a customer who has an onsite generating facility during unscheduled outages of the customer's on-site generator. Only applies to TOU-8-Standby-SEC, TOU-8-Standby-PRI, TOU-8-Standby-SUB Rate Groups.
4) Amount of energy included in the sales forecast that is not subject to transmission charges pursuant to the California Public Utilities Commission ("CPUC") approved Net Energy Metering Program.
5) Sales forecast pertaining to the sum of monthly maximum supplemental Mega-watt demand, applies to demand charge schedules
6) Sales forecast pertaining to the sum of monthly contracted standby Mega-watt demand, applies to standby schedules
7) Net Forecast in total Giga-watt hours usage - represents the customers' annual Net GWh, applicable to Non-Demand Charge Schedules such as Residential or Small General Service
8) Recorded sales from Sample meters adjusted for population - use to set the total demand rate for the optional time-of-use schedules within the GS-1 rate group
9) Line 1b2, Col11 = Line 1b Col9 * Line 1b Col11 * 10^6
10) Total demand rate for the optional time-of-use schedules within the GS-1 rate group, Line 1b2:Col10 = Line 1b2:Col12 (which = Line 1b2:Col11 / ((Line1b:Col12 + Line1b:Col13) * 10^3)
11) Sum of the TOU-8 Standby and TOU-8 Non-Standby billing determinants in Line1:Col6
12) For TOU-8 Rates revenue = Supplemental Demand Charge on Line 9 Column 8 * Maximum Demand on Lines 1 Column 6
13) For optional time-of-use schedules within the GS-1 rate group (Line16b:Col6), = (Line1b2:Col11 - Line16:Col3) / Line1b:Col12 / 10^3
14) For the non TOU-8-Standby rate group, it is the minimum of Line16i:Col7, or the total demand rate in Line1:Col10
15) Applicable to time-of-use schedules within the GS-1 rate group
16) Rates associated with Rate Groups GS-2 and TOU-GS-3 are calculated on a combined basis, so that the rate is the sum of the combined Revenue Associated with Supplemental Demand or Energy in Column 2 (line 16d and 16e) divided by the sum of the sum of the Billing Determinants in Column 8 (Line 1d and 1e).
17) Applicable to the optional schedules that contain horse power charge such as PA-1
18) GWh for TOU-8-Standby-SEC, TOU-8-Standby-PRI, TOU-8-Standby-SUB Rate Groups are placed in TOU-8-SEC, TOU-8-PRI, TOU-8-SUB Rate Groups respectively.

20

21

22 **Rate Schedules in each CPUC Rate Group:**
23
24

Line	CPUC Rate Group	Rate Schedules included in Each Rate Group in the Rate Effective Period
26a	Domestic	Includes Schedules D, D-CARE, D-FERA,TOU-D-T, TOU-EV-1, TOU-D-TEV, DE, D-SDP, D-SDP-O, DM, DMS-1, DMS-2, DMS-3, and DS.
	Domestic (con't)	D (Option CPP), D-CARE (Option CPP), TOU-D-Option A, TOU-D-Option B, TOU-D-3, TOU-D-T-CPP, TOU-D (Options 4-9 PM, 5-8 PM, PRIME, and CPP)
26b	TOU-GS-1	Includes Schedules GS-1, TOU-EV-3, TOU-EV-7 (Options D and E), and TOU-GS-1 (Options E, ES, D, LG, C, A, B, RTP, CPP, Standby, GS-APS, GS-APS-E, and ME).
26c	TC-1	Includes Schedules TC-1, Wi-Fi-1, and WTR.
26d	TOU-GS-2	Includes Schedules GS-2, TOU-EV-4, TOU-EV-8, and TOU-GS-2 (Options D, E, A, B, R, RTP, CPP, Standby, GS-APS, GS-APS-E, and ME).
26e	TOU-GS-3	Includes Schedules TOU-GS-3-CPP, TOU-EV-8, and TOU-GS-3 (Options D, E, A, B, R, RTP, SOP, Standby, TOU-BIP, GS-APS, GS-APS-E, and ME).
26f	TOU-8-SEC	Includes Schedules TOU-8-CPP, TOU-8-RBU, TOU-EV-9, and TOU-8 (Options D, E, A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26g	TOU-8-PRI	Includes Schedules TOU-8-CPP, TOU-8-RBU, TOU-EV-9, and TOU-8 (Options D, E, A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26h	TOU-8-SUB	Includes Schedules TOU-8-CPP, TOU-8-RBU, TOU-EV-9, and TOU-8 (Options D, E, A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26i	TOU-8-Standby-SEC	Includes Schedules TOU-8-Standby (Options D, LG, A, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26j	TOU-8-Standby-PRI	Includes Schedules TOU-8-Standby (Options D, LG, A, A2, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26k	TOU-8-Standby-SUB	Includes Schedules TOU-8-Standby (Options D, LG, A, A2, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26l	TOU-PA-2	Includes Schedules PA-1, PA-2, TOU-PA-ICE, and TOU-PA-2 (Options D, E, 4-9 PM, 5-8 PM, A, B, RTP, SOP-1, SOP-2, CPP, Standby, and AP-I).
26m	TOU-PA-3	Includes Schedules TOU-PA-3-CPP, and TOU-PA-3 (Options D, E, 4-9 PM, 5-8 PM, A, B, RTP, SOP-1, SOP-2, Standby, and AP-I).
26n	Street Lighting	Includes Schedules AL-2, AL-2-B, AL-2-F, DWL, LS-1, LS-2, LS-3, LS-3-B, and OL-1.
26o	---	

27
28
29 **Recorded 12-CP Load Data by Rate Group (MW)**

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
31–32					= Line35:(Col1+Col 2+Col3)/3			from Line1:Col3 Note 18	from Line1:Col4	= Col 7 + Col 8	= Line35:(Col4*Col5 /Col6*Col9)	= Line35:(Col10 / total of Col10)
33		12-CP MW									MW	
34	CPUC Rate Group	2014	2015	2016	3-Year Average	Line losses	Recorded GWh (Average)	Standby Adjusted Sales Forecast - GWh	Backup GWh	Total Sales Forecast - GWh	Loss Adjusted Average 12-CP	12-CP Allocation factors
35a	Domestic	68,997	70,775	70,601	70,124	1.0905	29,557	28,443	0	28,443	73,588	41.72%
35b	TOU-GS-1	12,145	12,889	12,483	12,506	1.0909	5,881	5,911	0	5,911	13,711	7.77%
35c	TC-1	85	83	82	83	1.0917	61	58	0	58	86	0.05%
35d	TOU-GS-2	30,524	30,626	29,452	30,201	1.0905	14,811	13,100	0	13,100	29,128	16.51%
35e	TOU-GS-3	16,197	16,184	15,947	16,109	1.0900	8,565	7,840	0	7,840	16,072	9.11%
35f	TOU-8-SEC	15,190	14,907	14,707	14,935	1.0909	8,586	8,168	0	8,168	15,500	8.79%
35g	TOU-8-PRI	9,949	9,882	9,684	9,838	1.0644	6,150	6,043	0	6,043	10,290	5.83%
35h	TOU-8-SUB	11,843	10,984	11,021	11,283	1.0315	7,868	7,540	0	7,540	11,153	6.32%
35i	TOU-8-Standby-SEC	101	143	155	133	1.0911	85	0	97	97	166	0.09%
35j	TOU-8-Standby-PRI	294	311	373	326	1.0645	236	0	243	243	358	0.20%
35k	TOU-8-Standby-SUB	587	631	714	644	1.0316	508	0	560	560	733	0.42%
35l	TOU-PA-2	3,189	3,024	2,748	2,987	1.0910	2,138	1,816	0	1,816	2,768	1.57%
35m	TOU-PA-3	1,846	1,833	1,891	1,857	1.0896	1,406	1,454	0	1,454	2,091	1.19%
35n	Street Lighting	812	660	685	719	1.0938	723	698	0	698	759	0.43%
35o	---											
36	Totals:	171,759	172,933	170,545	171,746		86,575	81,070	900	81,970	176,404	100.00%

Determination of Unfunded Reserves

Line		Reference			Prior Year Amount
1					
2					
3					Prior Year
4		Reference			Amount
5					
6	**Unfunded Reserves (EOY):**	(Line 17, Col 2)			-$10,717,922
7	**Unfunded Reserves (Average BOY/EOY):**	(Line 17, Col 3)			-$10,860,907
8					
9			**Col 1**	**Col 2**	**Col 3**
10			**Prior Year**	**Prior Year**	**Prior Year**
11			**BOY**	**EOY**	**Average**
12	**Description of Issue**		**Unfunded**	**Unfunded**	**Unfunded**
13	**Unfunded Reserves**		**Reserves**	**Reserves**	**Reserves**
14	Provision for Injuries and Damages	(Line 24)	-$6,902,253	-$6,450,199	-$6,676,226
15	Provision for Vac/Sick Leave	(Line 29)	-$3,535,741	-$3,702,212	-$3,618,976
16	Provision for Supplemental Executive Retirement Plan	(Line 36)	-$565,897	-$565,511	-$565,704
17	Totals:	(Line 14 + Line 15 + Line 16)	-$11,003,891	-$10,717,922	-$10,860,907
18					
19	**Calculations**				
20					Average
21	**Injuries and Damages**		BOY	EOY	BOY/EOY
22	Injuries and Damages - See Note 1	Company Records - Input (Negative)	-$114,763,336	-$107,247,069	
23	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	6.0143%	6.0143%	
24	ISO Transmission Rate Base Applicable	(Line 22 x Line 23)	-$6,902,253	-$6,450,199	-$6,676,226
25					
26	**Vacation Leave**				
27	Vacation and Personal Time Accruals - Acct. 2350080	Company Records - Input (Negative)	-$58,788,541	-$61,556,455	
28	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	6.0143%	6.0143%	
29	ISO Transmission Rate Base Applicable	(Line 27 x Line 28)	-$3,535,741	-$3,702,212	-$3,618,976
30					
31	**Supplemental Executive Retirement Plan**				
32	Supplemental Executive Retirement Plan	Company Records - Input (Negative)	-$18,818,284	-$18,805,421	
33	Times:	Applicable Rate Base Percentage	50%	50%	
34	Sub-Total Supplemental Executive Retirement Plan	(Line 32 x Line 33)	-$9,409,142	-$9,402,711	
35	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	6.0143%	6.0143%	
36	ISO Transmission Rate Base Applicable	(Line 34 x Line 35)	-$565,897	-$565,511	-$565,704

Notes:

1) Includes any Unfunded Reserves relating to accrued expenses included in Account 925 “Injuries and Damages”, reduced for any expected offsetting payments.

UNITED STATES OF AMERICA
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	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

EXHIBIT SCE-5

EXHIBIT TO THE TESTIMONY OF
MR. BERTON J. HANSEN

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

EXHIBIT SCE-5

FORMULA SPREADSHEET REVISIONS*

1) Substantive Changes:

Schedule/Location	Description of Change	Supporting Witness
Sch. 1, Line 50	Revise Return on Equity to 17.62% (Schedule 1, Line 50)	Wood SCE-19
Sch. 5, ROR-1	Add new Line 5 item “Unamortized Premium on Long Term Debt - Account 225”, and associated references, renumber remaining lines, and revise some changed references.	Deana SCE-17
Sch. 5, ROR-2 and ROR-3	Revisions relating to treatment of Long Term Debt that does not finance Rate Base when calculating capital structure: 1) Revise Line 8 ROR-2 description to read: “Removal of Long Term Debt Not Financing Rate Base ~~Related to Fuel Inventories~~” 2) Revise Line 9 ROR-2 description to read: “Adjustments related to “LT Debt Not Financing Rate Base ~~Related to Fuel Inventories~~” ” 3) Add Note 4 to ROR-3: Excludes debt, or portions thereof, that does not finance Rate Base	Deana SCE-17
Sch. 5 ROR-1	Add Line 4: “Unamortized Premium on Long Term Debt - Account 225” and renumber remaining lines.	Deana SCE-17
Sch. 5, ROR-1 and ROR-2	Revisions relating to including Wildfire Related Capital in capital structure: 1) Revise Line 18 of ROR-1 to be the sum of Lines 14 and 14a of ROR-2; 2) Add Line 14a “Proprietary Capital Adjustments for Wildfire Related Capital”; and 3) Add associated Note 14a: “Represents Capital disclosed by SCE related to Wildfire Related Capital, not yet paid on a cash basis. Amounts in Columns 2-14 are from SCE internal records”	Deana SCE-17
Sch. 5, ROR 3	Several revisions to use FERC Form 1 data to the extent possible:	Deana SCE-17

	1) Revise reference at top of Schedule to read "Prior year" rather than "At End of Year ("EOY") for Prior Year" 2) Line 3: Add yellow shading to signify cell is an input, and refer to FF1 117.64c Line 500, Column C 3) Line 7: Add reference to 5-ROR-2, Line 8, Col. 14 (Negative of FF1 111.81c) 4) New Lines 8-9: Add Composite Tax Rate on Line 8 and calculate "After Tax Total Unamortized Loss on Reacquired Debt" on Line 9, and change line references as appropriate 5) Line 10: Include Line 9 amount in total 6) Lines 101-133: Revise reference to Column 5 to FF1 257, Column h 7) Lines 101-133: Make entire Column 7 a yellow-shaded input column, and reference to FF1 256, Col c, and include reference to new Note 2 8) Lines 101-133: Column 9: Revise reference to Note 3 9) Lines 301-500: Delete entire modules 10) Revise Note 1 to read: "Equal to maturity date less the date of offering" 11) Add new Note 2: "Sum of all amounts for each issuance"	
Schedule 17	Revisions to better explain the dual purposes of Schedules 17 and 18: a) Revised Instruction 1: "1) Depreciation rates on lines 17a-17m are input based on the stated values of ISO Transmission Plant depreciation rates from Schedule 18 of the Formula Rate Spreadsheet in effect during the Prior Year." b) Revised Line 15: delete reference to Schedule 18	Gunn, SCE-7
Schedule 32, new Line 3	Added new Line 3 for new "Pump Load True-Up" (and renumbered remaining lines)	Hansen SCE-3
Schedule 32, new Note 4	Added Note 4: "4) The Pump Load True-Up value is equal to actual recorded less forecast Pump Load for the Prior Year."	Hansen SCE-3
Sch. 34, Line 22	Delete reference to Account 2251010 and add reference to new Note 1	Gunn SCE-7

Sch. 34, Line 22	Add new Note 1: "1) Includes any Unfunded Reserves relating to accrued expenses included in Account 925 "Injuries and Damages", reduced for any expected offsetting payments."	Gunn SCE-7

2) Typos and other non-substantive changes:

Schedule/Location	Description of Change	Supporting Witness
Sch. 4, Line 13	Change to "Prorata Avg." from "BOY/EOY Avg."	Hansen SCE-3
Sch. 5 ROR-2, Notes	Fix Line References on Notes 5-8 and 14-16 Schedule ROR-2	Deana SCE-17
Sch. 5 ROR-2, Line 13	Add missing Parenthesis to Label	Deana SCE-17
Sch. 5, ROR-2, Line 12	Delete "- of FF1"	Deana SCE-17
Sch. 5 ROR-4	Change all '000s to $000s	Deana SCE-17
Sch. 5 ROR-4, Line 6	Revise label for line to "Net Gain (Loss) from Purchase and Tender Offers", from "Total Unamortized Issuance Costs"	Deana SCE-17
Sch. 5 ROR-4, line 101	Fix typo before Line 101 to "Outstanding" from "Oustanding"	Deana SCE-17
Sch. 9, Line 12	Add "Prorata" to Line 12 description	Lopez, SCE-11
Sch. 9, Before Lines 1 and 10	Replace "ADIT" with "Balance" in Column 2 description	Lopez, SCE-11
Sch. 9, Line 7	Revise to read b) Beginning of Year Accumulated Deferred Income Taxes <u>and Net Excess Deferred Tax Liabilities</u>	Lopez, SCE-11
Sch. 9, Line 15	Revise to "Prorata Average Balance"	Lopez, SCE-11
Sch. 9, Notes 1 and 3	Spell out ADIT in notes: "Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities"	Lopez, SCE-11
Sch. 10	Insert missing column headers for several CWIP Project cost matrices (exactly the same as for other projects)	Hansen SCE-3
All Schedules	Revise line numbers as appropriate	Hansen SCE-3

3) Revised or additional Inputs relative to TO2019 filed November 29, 2018:

Schedule/Location	**Description of Change**	**Supporting Witness**
Sch. 3, Line 23	Revised One Time Adjustment amount of $78,692,427	Hansen SCE-3
Sch. 32, Line 3	Include new "Pump Load True-Up" amount of 8,618 MWh (Schedule 32, Line 3)	Hansen SCE-3
Sch. 5 ROR-2, Line 9	Revise to -$100,000,000 for January through October	Deana SCE-17
Sch. 5 ROR-2, Line 10	Revise to $0 for all months	Deana SCE-17
Sch. 5 ROR-3	Lines 120 and 121, Column 5: Revise to $353,751 and $325,000 respectively, and delete associated Notes 3 and 4	Deana SCE-17
Sch. 26 Note 1	Revise federal income tax rate source to "Internal Revenue Code § 11.b"	Lopez SCE-17

*Relative to the currently-effective Formula Spreadsheet (Appendix IX, Attachment 2 of SCE's Transmission Owner Tariff). The currently-effective Formula Spreadsheet tariff is as filed in Docket No. ER19-1149 with an effective date of March 1, 2019 ("CPUC Phase 2 Order Rate Schedule Filing"), as revised in ER19-1226 (PBOPS Amount Revision).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

EXHIBIT SCE-6

EXHIBIT TO THE TESTIMONY OF MR. BERTON J. HANSEN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

EXHIBIT SCE-6

Formula Rate Protocol Revisions*

Protocol Section	Description of Change**
Section 1, footnote 1, and other locations	Define and refer to the current Formula Rate (effective 2018 through the effective date of this proposed new Formula Rate) as the "Second Formula Rate"
Section 2	Describe the effective date of this proposed Formula Rate as "the date the Commission determines"
Section 3, footnote 4	Revise the definition of "Material Accounting Change" to be: "Material Accounting Changes" shall mean any material change that affects SCE's transmission rates as follows: (i) accounting policies and practices from those in effect for the Prior Year upon which the immediately preceding Annual Update was based, including those resulting from any new or revised accounting guidance from the Financial Accounting Standards Board; or (ii) internal corporate cost allocation policies or practices in effect for the Prior Year upon which the immediately preceding Annual Update was based; or (iii) income tax elections from those in effect for the Prior Year upon which the immediately preceding Annual Update was based; or (iv) cost allocation policies between EIX, SCE, and subsidiaries of either, from those in effect for the Prior Year upon which the immediately preceding Annual Update was based. Additionally, a Material Accounting Change shall also include any: (i) initial implementation of an accounting standard; or (ii) initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction.
Section 4, first paragraph	Insert "or a previous formula rate" to ensure all cases are covered.
Section 4, part e	Add the following language to ensure that Final True Up Adjustments for the 2018 and 2019 years are included in future Base TRRs: The True Up Adjustment included in the Base TRR effective January 1, 2020 shall include the Final True Up Adjustment for the 2018 year calculated pursuant to the Second Formula Rate. The True Up Adjustment included in the Base TRR effective January 1, 2021 shall include the Final True Up Adjustment for the portion of the 2019 year for which the Second Formula Rate was in effect, calculated pursuant to the Second Formula Rate.

Section 6 Title	Revise title to be: "Transition of the Original and Second Formula Rates to Successor Formula Rates".
Section 6, second paragraph	Delete unnecessary language having to do with the possibility that the Original Formula Rate would not become effective until a date after January 1, 2018.
Section 6, new third paragraph	Add paragraph to generally describe the transition from any formula rate to its successor formula rate, and to state that if a calendar year has more than one formula rate in effect, the True Up TRR for that year will be based on the weighted average of the True Up TRRs associated with the two or more formulas in effect, with the weighting to be based on the number of days each is in effect.
Section 8, part b	Delete unnecessary initial value of "Authorized PBOPs Expense Amount".

*Relative to the currently-effective Formula Protocols (Appendix IX, Attachment 1 of SCE's Transmission Owner Tariff). The currently-effective Formula Protocols are as filed and approved in Docket No. ER18-2440, effective date of November 16, 2018.

** All proposed revisions to the Formula Protocols are supported by Mr. Hansen in Exhibit No. SCE-3.

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF

DAVID C. GUNN

ON BEHALF OF

SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-7)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
DAVID C. GUNN

(EXHIBIT SCE-7)

Mr. Gunn supports the depreciation rates for transmission plant and explains the formulas for determining many of the components of Rate Base used in determining the Prior Year Transmission Revenue Requirement ("Prior Year TRR") and the True Up Transmission Revenue Requirement ("True Up TRR"). He also describes the formula for determining the Depreciation Expense component of the Prior Year TRR and the True Up TRR, including the Wholesale Depreciation Difference and the determination of forecast additions to plant in-service and Construction Work in Progress ("CWIP") utilized in determining the Incremental Forecast Period Transmission Revenue Requirements ("IFPTRR") component of the Base Transmission Revenue Requirements ("Base TRR").

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Southern California Edison Company	**)))**	**Dkt. No. ER19-______-000**

**PREPARED DIRECT TESTIMONY OF
DAVID C. GUNN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY**

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

A. My name is David C. Gunn, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am currently a Senior Advisor in SCE's Capital Asset Analytics Department. As such, I am responsible for forecasting rate base and depreciation expense, supporting depreciation studies, and developing testimony and workpapers in support of SCE's filings with the CPUC and FERC.

Q. Briefly describe your education and professional background.

A. I have a Bachelor of Science degree in Business Administration, with an emphasis in Accounting from California State University, Los Angeles. Prior to my current role I worked in the Plant Accounting organization and my primary responsibility was designing metrics and modeling tools supporting SCE's goals of timely and accurate work order accounting. I started in my current position as a Project Manager at SCE in March of 2016.

Q. Have you submitted testimony to the Commission previously?

A. Yes. I submitted testimony regarding depreciation rates for transmission plant in Docket No. ER18-169-000.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

1) support the proposed depreciation rates for transmission plant included in the proposed Formula Rate as shown on Schedule 18;
2) explain the formulas for determining many of the components of Rate Base used in determining the Prior Year Transmission Revenue Requirement ("Prior Year TRR") and the True Up Transmission Revenue Requirement ("True Up TRR") on Schedules 6, 8, 10, 11, 13, and 34;
3) explain the formula for determining the Depreciation Expense component of the Prior Year TRR and the True Up TRR, including the Wholesale Depreciation Difference on Schedule 17 and 25; and
4) explain the determination of forecast additions to plant in-service and Construction Work in Progress ("CWIP") utilized in determining the Incremental Forecast Period Transmission Revenue Requirements ("IFPTRR") component of the Base Transmission Revenue Requirements ("Base TRR") on Schedules 10 and 16.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 1 (Base TRR), Line 7 relating to Cash Working Capital, Schedule 6 (Plant in Service), Schedule 8 (Accumulated Depreciation), Schedule 10 (CWIP), Schedule 13 (Working Capital), a portion of Schedule 14 (Incentive Plant) relating to Net Plant in Service for Incentive Projects (Lines 39-182), Schedule 16 (Plant Additions), Schedule 17 (Depreciation), Schedule 18 (Depreciation Rates), and Schedule 34 (Unfunded Reserves).

Q. Does your testimony address any changes in the proposed Formula Rate compared to SCE's currently-effective Formula Rate (the "Second Formula Rate")?

A. No. However, I am proposing a revision to Schedule 17 to clarify the separate purposes of Schedules 17 and 18. Line 15 of Schedule 17 will no longer reference Schedule 18. In addition, I am proposing the following changes to Instruction 1 of Schedule 17, as reflected below:

Instruction 1:

~~1) Depreciation rates on Lines 17a-17m input from Schedule 18. However, in the event of a change in depreciation rates approved by the Commission, use Commission-approved depreciation rates that were in effect during the Prior Year.~~

1) Depreciation rates on lines 17a-17m are input based on the stated values of ISO Transmission Plant depreciation rates from Schedule 18 of the Formula Rate Spreadsheet in effect during the Prior Year.

I. DEPRECIATION EXPENSE

Q. Please describe Depreciation Expense.

A. Depreciation Expense is comprised of three subcomponents: 1) Depreciation Expense for Transmission Plant – ISO; 2) Depreciation Expense for Distribution Plant – ISO; and 3) Depreciation Expense for General Plant & Intangible Plant.

Q. How does the Formula Rate determine the amount of Depreciation Expense for Transmission Plant – ISO?

A. Depreciation Expense for Transmission Plant – ISO is calculated on a monthly basis at the FERC Plant Account level in Schedule 17. It is calculated by multiplying monthly depreciation expense rates (annual rate / 12) by the prior month ending balance of Transmission Plant – ISO for each account. SCE will calculate depreciation expense with the rates consistent with the depreciation study results from its pending 2018 GRC application.

Q. Does these values differ from those in the current Formula Rate?

A. No, SCE's proposed depreciation rates for Transmission Plant – ISO are the same as those currently in effect in SCE's currently-effective Formula Rate.

Q. Why are SCE's proposed depreciation rates reasonable?

A. The objective of depreciation is to allocate the capital cost of assets (including their future cost to retire) over their useful life. SCE's most recent depreciation study showed that SCE's FERC Transmission depreciation rates, that were in effect during the term of SCE's Original Formula Rate (2012 through 2017), did not adequately allocate capital costs. To remedy this, SCE proposed in the currently-effective Formula Rate to use the well supported depreciation rates developed in its most recent CPUC GRC. In its GRC filing, SCE performed a detailed study to calculate the service life, net salvage, and depreciation rate characteristics of its assets. The detailed study results represent SCE's current best estimate of the life and net salvage parameters necessary to allocate the cost of Transmission plant over its useful life. Exhibit No. SCE-8 presents SCE's GRC depreciation rate testimony including a summary of the depreciation rate study. In this filing, SCE is proposing these same depreciation rates.

It is worth noting that the most current depreciation study's proposal for Transmission service life is the results of SCE's first actuarial life analysis. In addition, SCE augmented its net salvage analysis with a detailed per-unit study to estimate the future cost to retire assets. For three Transmission accounts (354, 355, and 356), SCE's per-unit analysis:

1) separated investment into major sub-populations (*i.e.*, Towers supporting infrastructure above and below 220kV separately);
2) estimated the current cost to retire assets from service using 7 years of recorded history; and
3) paired the recent per-unit costs with the results of SCE's actuarial analysis

to forecast the timing and level of future retirements and expected inflation for the cost to retire each unit.

SCE performed the detailed per-unit analysis on these three accounts because they represent accounts with the highest estimated future cost to retire which results in the highest depreciation rates. Thus, the FERC plant accounts with the most negative net salvage rates (with the highest cost of removal depreciation rates) are also the most well documented and supported.

Finally, the results of study were moderated by SCE's application of "gradualism."[1] Specifically, SCE capped its depreciation rates by limiting changes in net salvage ratios to no more than 25% of the currently authorized values. As a result, SCE's depreciation rate proposal is both a conservative and well supported means of calculating Transmission Plant – ISO depreciation expense.

Q. How does the proposed Formula Rate determine the amount of Depreciation Expense for Distribution Plant – ISO?

A. Depreciation Expense for Distribution Plant – ISO is calculated on an annual basis at the FERC Plant Account level in Schedule 17. It is derived by multiplying the annual depreciation expense rate by the simple Beginning of Year ("BOY") End of Year ("EOY") average of Distribution Plant – ISO. The depreciation rates for Distribution Plant – ISO accounts are based on SCE's currently-authorized California Public Utilities Commission depreciation rates. This is the same methodology used in the Second Formula Rate.

Q. How does the proposed Formula Rate determine the amount of Depreciation Expense for General Plant & Intangible Plant?

A. Annual Depreciation Expense for General & Intangible Plant is based on total amounts of General and Intangible Plant Depreciation Expense as recorded in

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1 In prior GRC's, the CPUC has moderated requested increases for net salvage accruals with the application of gradualism as a means to mitigate the rate impact to customers.

SCE's annual FERC Form 1 filing. The amount of General and Intangible Plant Depreciation Expense included in this proposed Formula Rate is equal to these total amounts of General and Intangible plant times the Transmission Wages and Salaries Allocation Factor. General & Intangible Plant Depreciation Expense is calculated in Schedule 17. This is the same methodology used in the Second Formula Rate.

Q. Please explain the Wholesale Depreciation Difference component of the Wholesale Base TRR.

A. The difference in retail and wholesale book depreciation reserves stems from differences in authorized depreciation rates in the respective jurisdictions prior to the implementation of the California Independent System Operator Corporation ("ISO") in 1998. Prior to 1998, FERC had authorized depreciation rates for wholesale customers that were substantially lower than those authorized by the CPUC for retail customers. To compensate for this difference, the Commission authorized the establishment of retail and wholesale adjustments to the accumulated depreciation reserve. The retail and wholesale reserve adjustments were to be amortized equally over a 27 year period. SCE's proposed Formula Rate contains both the simple average (BOY/EOY) of the reserve adjustment in Rate Base and the annual amortization included in depreciation expense for both retail and wholesale customers. The Wholesale Depreciation Difference is presented in Schedule 25, Line 32 of Exhibit No. SCE-4. This is the same methodology used in the Second Formula Rate.

II. RATE BASE

Q. Please define the Prior Year TRR and explain how it is used.

A. The Prior Year TRR represents SCE's actual cost of service in the Prior Year as recorded at end of year ("EOY"). It is calculated using inputs from SCE's FERC Form 1 from the prior year and is supplemented by the same SCE accounting records used to populate the FERC Form 1. The Prior Year TRR is a component of the Base TRR. The Base TRR is used to set SCE's transmission rates during the Rate Year at a level that approximates SCE's actual costs to be experienced during that time. The components of the Prior Year TRR are described in detail in Mr. Hansen's testimony, Exhibit No. SCE-3. The Prior Year TRR is calculated in Schedule 1, Line 81 of the proposed Formula Rate (Exhibit No. SCE-4).

Q. Please define the True Up TRR and explain how it is used.

A. True Up TRR defines the actual transmission costs that SCE incurred during the Prior Year and is also the amount of transmission costs that SCE ultimately receives through the operation of the proposed Formula Rate. For the True Up TRR, the amount of Rate Base is determined on an average basis, rather than the EOY basis used to determine the Prior Year TRR. The True Up TRR is calculated in Schedule 4 of the proposed Formula Rate. A description of the True Up TRR is described in Mr. Hansen's testimony, Exhibit No. SCE-3.

Q. What are the components of the proposed Formula Rate used for determining the Rate Base in the Prior Year TRR and True Up TRR in the formula?

A. SCE includes the following components of Rate Base:

1) ISO Transmission Plant (Schedule 6)
2) General and Intangible Plant (Schedule 6)
3) Plant Held for Future Use (Schedule 11)
4) Abandoned Plant (Schedule 12)
5) Working Capital (Schedule 13)
6) Cash Working Capital (Schedule 1, Line 7)
7) Accumulated Depreciation Reserve (Schedule 8)
8) Construction Work in Progress (Schedule 10)
9) Other Regulatory Assets/Liabilities (Schedule 23)
10) Unfunded Reserves (Schedule 34)
11) Network Upgrade Credits (Schedule 22)
12) Accumulated Deferred Income Taxes (Schedule 9)

Q. Which of these components of the Rate Base formula are you supporting in your testimony?

A. I am supporting the following components:

1) ISO Transmission Plant (Schedule 6)
2) General and Intangible Plant (Schedule 6)
3) Plant Held for Future Use (Schedule 11)
4) Working Capital (Schedule 13)
5) Cash Working Capital (Schedule 1, Line 7)
6) Accumulated Depreciation Reserve (Schedule 8)
7) Construction Work in Progress (Schedule 10)
8) Unfunded Reserves (Schedule 34)

Mr. Ocegueda in Exhibit No. SCE-15 supports Abandoned Plant, Other Reg Assets, and Network Upgrade Credits, and Mr. Lopez in Exhibit No. SCE-11 supports the Accumulated Deferred Income Taxes component of Rate Base.

Q. What values are used in determining the Rate Base for the Prior Year TRR?

A. As discussed above, SCE's Prior Year TRR uses Rate Base calculated on an EOY basis. Mr. Hansen in Exhibit No. SCE-3 explains this aspect of the overall proposed Formula Rate.

Q. What values are used in determining the Rate Base for the True Up TRR?

A. As discussed above, SCE's True Up TRR Rate Base is calculated on a weighted average basis. In the case of "Transmission Plant – ISO," "Transmission Depreciation Reserve – ISO," "Working Capital" (Materials and Supplies and Prepayments), and "CWIP Plant," a 13-month average balance is used. For the other components of Rate Base a simple average is calculated using Beginning of Year ("BOY") and EOY balances. Mr. Hansen in Exhibit No. SCE-3 explains this aspect of the overall proposed Formula Rate.

A. ISO Transmission Plant

Q. Please explain the ISO Transmission Plant component of Rate Base.

A. ISO Transmission Plant represents the amount of Plant-In-Service reported in

SCE's annual FERC Form 1 filing that is under the Operational Control of the California Independent System Operator Corporation ("CAISO"), and whose costs are recovered through the proposed Formula Rate. SCE performs a Transmission Plant Study (Schedule 7 of Exhibit No. SCE-4) categorizing its historic investment of transmission and distribution plant as either ISO or non-ISO. For details of the study, see Mr. Moon's testimony in Exhibit SCE-9. SCE's proposed Formula Rate relies on the same calculation methodology to determine Transmission Plant – ISO as was used in the Second Formula Rate and is discussed below.

Q. How does the proposed Formula Rate determine the amount of Transmission Plant – ISO for Prior Year TRR?

A. EOY Transmission Plant ISO balances are used for Prior Year TRR based on results from the Transmission Plant Study.

Q. How does the proposed Formula Rate determine the amount of Transmission Plant – ISO for True Up TRR?

A. For True Up TRR, SCE calculates the 13-month average balance of Transmission Plant – ISO by FERC Plant Account in Schedule 6. Beginning of Year ("BOY") and End of Year ("EOY") Transmission Plant – ISO balances are sourced from the Transmission Plant Study summary. The EOY Transmission Plant – ISO balances are sourced from the Transmission Plant Study summary in Schedule 7. Because SCE does not account for its plant on an ISO and Non-ISO basis, the monthly Transmission Plant – ISO balances (January through November) must be calculated. To do so, SCE adds to its beginning ISO balances the allocated annual change in Non-Incentive ISO Transmission Plant – ISO and incentive plant activity.[2] To determine the monthly allocation of the annual change in Non-Incentive ISO Transmission plant SCE's proposed Formula Rate uses a four-step

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[2] Incentive plant is treated as 100% ISO and is tracked on a monthly basis by SCE. As such, it does not require calculations to determine monthly balances. Incentive plant is available in Schedule 14 of the proposed Formula Rate (Exhibit No. SCE-4).

process:

1) SCE takes the difference in monthly balances to calculate monthly activity for total Transmission Plant (not jurisdictionalized).
2) From the amounts in Step 1, SCE subtracts the activity attributable to incentive plant to calculate Non-Incentive Transmission Plant activity
3) Divide resulting monthly Non-Incentive Transmission Plant activity by the annual change in Non-Incentive Plant Activity to calculate monthly allocation percent for each FERC Plant Account.
4) Multiply the annual change in Non-Incentive ISO Plant by the monthly allocation percentages calculated in Step 3 to assign annual change to each month.

The calculation of monthly balances, from beginning to end, is summarized in the diagram below.

Monthly Change in Transmission Plant		Annual Change in ISO Plant		Allocation of Monthly ISO Plant
Total Transmission Plant Activity		Change in ISO Plant		
-		-		
Incentive Plant Activity		Change in Incentive Plant		
=		=		
Non-Incentive Plant Activity	x	Annual Change in Non-Incentive ISO Plant	=	Non-Incentive Transmission Plant
				+
				Incentive Plant Activity
				=
				ISO Transmission

Q. Why is Incentive Plant treated differently in this calculation?

A. Incentive plant is treated as 100% ISO and is tracked on a monthly basis by SCE. As such, it does not require calculations to determine monthly balances. Incentive plant is available in Schedule 14 of the proposed Formula Rate (Exhibit No. SCE-4).

Q. Does this methodology represent a change from the Second Formula Rate?

A. No. The presentation of the data has changed to increase transparency and show the results of the diagram above, but the shaping mechanism and calculation methodology remain the same as that used in the Second Formula Rate.

B. General and Intangible Plant

Q. Please explain the General Plant component of Rate Base in the proposed Formula Rate.

A. As indicated above, for purposes of Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, SCE determines the simple average (BOY/EOY) balance of the General Plant component of Rate Base utilizing the total amounts of General Plant reported in SCE's annual FERC Form 1 filing. The average balance of the total amount of General Plant is then allocated to the transmission Rate Base in this formula rate using the Transmission Wages and Salaries Allocation Factor. General Plant is presented in Schedule 6 of Exhibit SCE-4. This is the same methodology used in the Second Formula Rate.

Q. Please explain the Electric Miscellaneous Intangible Plant component of Rate Base in the proposed Formula Rate.

A. For purposes of the Prior Year TRR the value is based on EOY balances. For purposes of the True Up TRR, SCE determines the simple average (BOY/EOY) balance of the Electric Miscellaneous Intangible Plant ("Intangible Plant") component of Rate Base utilizing the total amounts of Intangible Plant reported in SCE's annual FERC Form 1 filing. The average balance of total Electric Miscellaneous Intangible Plant is then allocated to the Rate Base in this formula rate using the Transmission Wages and Salaries Allocation Factor. Electric Miscellaneous Intangible Plant is presented in Schedule 6 of Exhibit SCE-4. This is the same methodology used in the Second Formula Rate.

C. Plant Held for Future Use

Q. Please explain the Transmission Plant Held for Future Use component of Rate Base in the proposed Formula Rate.

A. Transmission Plant Held for Future Use (" PHFU") is typically comprised of land or land rights purchased in advance of Transmission Plant construction and allocation of General PHFU. As indicated above, for purposes of the Prior Year TRR the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average. PHFU is analyzed at the work order level to determine land or land rights related to construction of assets intended to be placed under the Operational Control of the ISO. All work orders associated with Incentive Construction Work In Progress (Incentive CWIP) projects are excluded from this component of Rate Base. An allocated portion of General PHFU is included in transmission PHFU based on the Transmission Wages and Salaries Allocation Factor. Transmission PHFU is calculated in Schedule 11 of Exhibit No. SCE-4. The PHFU value of $9,942,155 shown on Schedule 11, Line 2a of Exhibit No. SCE-4 is an allocation of land rights for SCE's proposed Alberhill Substation. This is the same methodology used in the Second Formula Rate.

D. Working Capital

Q. Please explain the Working Capital component of Rate Base in the proposed Formula Rate.

A. Working Capital is composed of three subcomponents: 1) Materials and Supplies; 2) Prepayments; and 3) Cash Working Capital. The Materials and Supplies and Prepayments components of Working Capital are calculated in Schedule 13 of Exhibit No. SCE-4, while the Cash Working Capital is calculated in Schedule 1, Line 7 of Exhibit No. SCE-4.

Q. How does the proposed Formula Rate determine the amount of Materials and Supplies?

A. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a 13-month average and allocated in the formula rate using the Transmission Wages and Salaries Allocation Factor. Materials and Supplies BOY/EOY balances are derived using total amounts of Materials and Supplies reported in SCE's annual FERC Form 1 filing. January through November balances are derived using total amounts of Materials and Supplies sourced from SCE Records consistent with its FERC Form 1 filing. This is the same methodology used in the Second Formula Rate.

Q. How does the proposed Formula Rate determine the amount of Prepayments?

A. Prepayments BOY and EOY balances are derived using amounts reported in SCE's annual FERC Form 1 filing. January through November balances are derived using total amounts of Prepayments from SCE Records. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a 13-month average and allocated using the Transmission Wages and Salaries Allocation Factor. This is the same methodology used by SCE's Second Formula Rate.

Q. Has SCE performed a lead lag study for FERC working capital requirements?

A. No. While SCE has performed a lead lag study for use in its CPUC GRC, SCE has not performed a FERC specific lead lag study.

Q. Can SCE modify its GRC lead lag study to apply specifically to Transmission customers?

A. No, SCE's CPUC GRC lead lag study was performed on a total company basis and did not separate its cash working capital requirements into different business operations. Refinement of the existing study to this more granular level of detail would require an additional study to classify SCE's accounting records into specific business operations. Because SCE has not performed this study, a FERC jurisdictional lead lag study is not available.

Q. How does the proposed Formula Rate determine the amount of Cash Working Capital?

A. In light of the fact that SCE does not have a FERC jurisdictional lead lag study , the amount of cash working capital is calculated by taking 1/8 of ISO Operations and Maintenance ("O&M") Expense plus Administrative and General ("A&G")

Expense. In other words, SCE is applying the 45 day convention in the proposed Formula Rate.

Q. Is this consistent with FERC policy?

A. I understand that in the absence of a FERC jurisdictional lead lag study, it is FERC policy to apply the 45 day convention.[3]

Q. Does this differ from the Second Formula Rate methodology?

A. No. In the Second Formula Rate calculation, Cash Working Capital also is calculated as 1/8 of ISO O&M plus A&G Expense.

E. Accumulated Depreciation Reserve

Q. Please explain the Accumulated Depreciation Reserve component of Rate Base in the proposed Formula Rate.

A. Accumulated Depreciation Reserve is comprised of three subcomponents: 1) Transmission Depreciation Reserve – ISO; 2) Distribution Depreciation Reserve – ISO; and 3) General Plant & Intangible Depreciation Reserve.

Q. How does the proposed Formula Rate determine the amount of Transmission Depreciation Reserve – ISO?

A. Transmission Depreciation Reserve – ISO is the amount of accumulated depreciation associated with Transmission Plant – ISO by FERC Plant Account. It is calculated in Schedule 8. As indicated above, for purposes of the Prior Year TRR the value is based on EOY balances. For purposes of the True Up TRR, the value is calculated using a 13-month average balance. The BOY and EOY Transmission Depreciation Reserve – ISO balance inputs are derived from SCE's Transmission Plant Study from each respective period. To develop the

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[3] *See Carolina Power & Light Co.*, 6 FERC ¶ 61,154 at 61,296 (1979)*; Louisiana Power & Light Co.*, 14 FERC ¶ 61,075 at 61,122-23; and *Trans-Elect NTD Path 15, LLC*, 117 FERC ¶ 61,214 at 32,39-43 (2006).

Transmission Depreciation Reserve – ISO balances for January through November, Transmission Depreciation Reserve – ISO activity is allocated by month using recorded monthly Total Transmission Plant activity found in Schedule 6 of Exhibit No. SCE-4. The steps used to calculate these allocation factors are described in Section A, "ISO Transmission Plant," earlier in my testimony.

Q. Does the formula differ from the methodology used in the Second Formula Rate?

A. No. Consistent with the Second Formula Rate, Total Transmission Depreciation Reserve –ISO activity is allocated using Total Transmission Plant activity percentages calculated on Schedule 6 of Exhibit No. SCE-4.

Q. Why does SCE rely on Transmission Plant – ISO allocation factors calculated on Schedule 6 of the proposed Formula Rate (Exhibit No. SCE-4)?

A. These allocation factors represent a reasonable proxy for the change in reserve balances because many of the transactions that affect plant activity have associated effects on depreciation reserve activity. For example, retirements effect both plant and reserve balances equally. Similarly, cost of removal often affects the depreciation reserve at the same time that plant balances are affected by a capital addition.

Q. How does the proposed Formula Rate determine the amount of General Plant & Intangible Depreciation Reserve?

A. For purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average utilizing the total amount of Depreciation Reserve in SCE's annual FERC Form 1 filing. The balance is then allocated to the Accumulated Depreciation Reserve component of Rate Base in the proposed Formula Rate using the Transmission Wages and Salaries Allocation Factor. General Plant & Intangible Plant Depreciation Reserve is presented in Schedule 8 of Exhibit No. SCE-4. This is the same methodology used by SCE's Second Formula Rate.

F. Construction Work in Progress Plant – Prior Year

Q. Please explain the Construction Work In Progress Plant – Prior Year component of Rate Base.

A. Construction Work In Progress Plant – Prior Year ("CWIP -- Prior Year") is the balance of construction work in progress for Incentive Transmission projects the Commission has authorized SCE to include in rate base. It is presented in Schedule 10 of Exhibit No. SCE-4. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, it is calculated using a 13 month average. For details of SCE's approved incentive transmission projects that contribute to CWIP – Prior Year, see Mr. Moon's testimony in Exhibit SCE-9.

G. Unfunded Reserves

Q. Please explain the Unfunded Reserves component of Rate Base.

A. Unfunded Reserves is composed of three subcomponents: 1) Injuries and Damages; 2) Vacation Leave; and 3) Supplemental Executive Retirement Plan. All three subcomponents are calculated in Schedule 34 of Exhibit No. SCE-4.

Q. How does the proposed Formula Rate determine the amount of Injuries and Damages?

A. Injuries and Damages BOY/EOY balances are derived using total amounts from SCE Records. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average and allocated in the formula rate using the Transmission Wages and Salaries Allocation Factor. This is the same methodology as was used in the Second Formula Rate.

Q. How does the proposed Formula Rate determine the amount of Vacation Leave?

A. Vacation Leave BOY/EOY balances are derived using total amounts from SCE's Records. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average and allocated using the Transmission Wages and Salaries Allocation Factor. This is the same methodology as was used in the Second Formula Rate.

Q. How does the formula rate determine the amount of Supplemental Executive Retirement Plan?

A. Supplement Executive Retirement Plan BOY/EOY balances are derived using total amounts from SCE's Records. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average. First, the average amount is multiplied by the applicable Rate Base percentage, and then allocated using the Transmission Wages and Salaries Allocation Factor. This is the same methodology as was used in the Second Formula Rate.

Q. Is SCE proposing any changes to Schedule 34 "Unfunded Reserves"?

A. Yes. SCE is proposing to delete the reference to the specific Account 2251010 on Line 22 of Schedule 34 relating to Injuries and Damages Unfunded Reserves, and replace it with a Note 1: "Includes any Unfunded Reserves relating to accrued expenses included in Account 925 "Injuries and Damages", reduce for any expected offsetting payments". These changes clarify the nature of the costs to be included on Line 22 relating to the Injuries and damages component of Unfunded Reserves.

III. TRANSMISSION INCENTIVE PLANT NET PLANT IN SERVICE

Q. Does the formula determine amounts of ISO Transmission Plant eligible to receive Return on Equity adders?

A. Yes. For each project for which SCE has received Commission approval to include a Return on Equity ("ROE") adder in the determination of SCE's total ROE, the formula quantifies the net plant in service eligible to receive such an adder. This amount is called "Transmission Incentive Plant Net Plant In Service." Mr. Hansen in Exhibit No. SCE-3 explains how the amount of Transmission Incentive Plant Net Plant In Service is used to calculate the dollar amount of ROE adders included in the Prior Year TRR and True Up TRR.

Q. Please describe how the formula determines Transmission Incentive Plant Net Plant-In-Service.

A. Transmission Incentive Plant Net Plant-In-Service is the amount of recorded Plant-In-Service less Accumulated Depreciation associated with projects that have received Commission authorization to receive an ROE adder. Transmission Incentive Plant Net Plant-In-Service is provided by project in Schedule 14 of Exhibit No. SCE-4. As indicated above, for purposes of the Prior Year TRR the value is based on EOY balances. For purposes of the True Up TRR, Transmission Incentive Plant Net Plant-In-Service is calculated using a 13-month average. This is the same methodology as was used in the Second Formula Rate.

IV. FORECAST INFORMATION USED IN DEVELOPING THE INCREMENTAL FORECAST PERIOD TRR ("IFPTRR")

Q. What forecasts are you supporting that will be used in the calculation of the IFPTRR?

A. I am supporting forecasts of two amounts: 1) Forecast Net Plant Additions on Schedule 16; and 2) Forecast Period Incremental CWIP on Schedule 10.

Q. How are these two forecasts used in this formula?

A. Both of these forecast amounts will be used in the calculation of the IFPTRR in

Schedule 2. These forecast amounts represent balances that will be included in SCE's Rate Base during the Forecast Period, and thus contribute to SCE's Base TRR in the Forecast Period. Mr. Hansen, in Exhibit SCE-3, fully explains how they are used and contribute to the amount of the IFPTRR.

Q. What dollar amounts are included in Mr. Moon's forecast capital expenditures?

A. Mr. Moon's forecast of capital expenditures includes only the direct capital expenditures for the Transmission / Distribution Business Unit ("TDBU") for each project. Direct expenditures include costs for materials, direct TDBU labor, costs for removal, and TDBU divisional overheads. The divisional overheads are costs that support a group of construction projects within a division of the company (*i.e.,* costs that cannot be assigned to any one particular project). These costs include TDBU divisional management, TDBU administration and accounting, as well as costs for supplies and tools.

Q. Please describe how you develop the Forecast Net Plant Additions to be incorporated into the Incremental Forecast Period TRR.

A. I develop Forecast Net Plant Additions based on direct capital expenditure forecast information for projects that are expected to be placed in service by the end of the Forecast Period. Details on capital projects including SCE's annual expenditure forecast and expected completion date (s) or blanket close designation for each budget item can be found in Mr. Moon's testimony, Exhibit SCE-9. I convert the direct capital expenditures provided by Mr. Moon and the recorded CWIP balances from the last recorded year into a monthly forecast of unloaded Transmission Plant additions. SCE includes all components of construction cost as prescribed in Part 18 of the Code of Federal Regulations, Part 101, paragraph 3 of the Electric Plant Instructions (18 CFR Part 101).

Q. What are Corporate Overheads and AFUDC?

A. Corporate overheads are similar to capitalized divisional overheads; however, they support all SCE capital projects, rather than projects for a particular division of the company. Forecast capitalized corporate overheads consist of costs for Corporate Administrative & General (A&G), Pensions & Benefits (P&B), Payroll Taxes, Property Taxes, and Injuries & Damages. On Schedules 10 and 16 of Exhibit SCE-4, SCE adds a 7.5% loader to unloaded forecast additions to reflect the capitalized overheads added to construction projects.

AFUDC is the generally accepted regulatory accounting procedure to capitalize the cost of debt and equity funds used to finance the construction of capital additions. It compensates investors for the cost of supplying funds for a capital project during construction before an asset is used and useful and is added to rate base. Once in rate base, AFUDC is shut off and return can be collected from ratepayers. On Schedule 16 of Exhibit No. SCE-4, SCE adds a 3.0% loader to unloaded forecast additions to reflect the AFUDC financing costs of constructing capital projects.

SCE's methodology for applying Corporate Overheads and AFUDC is the same as the Second Formula Rate.

Q. What is Cost of Removal?

A. Cost of Removal is the capital cost required to retire assets at the end of their service life. Cost of removal is accrued (credited) to accumulated depreciation during the monthly calculation of depreciation expense. When actual removal costs are incurred, cost of removal expenditures decrease (debit) prior accruals for removal costs. Eight percent of the Non-Incentive forecast transmission capital activity are estimated to be removal related and are reclassified from Gross Plant to Accumulated Depreciation.

Q. How does SCE incorporate Corporate Overheads on Schedule 10?

A. Schedule 10 of Exhibit No. SCE-4 includes a forecast of incentive plant additions. SCE adds to the incremental Incentive activity (*i.e.*, amounts spent and/or closed during the forecast period) a corporate overhead adder of 7.50% to reflect in plant the effects of estimated corporate overheads.

Q. How does SCE incorporate Corporate Overheads, AFUDC, and Cost of Removal on Schedule 16?

A. Forecast capital activity for non-incentive Transmission Activity is entered on Schedule 16 of Exhibit No. SCE-4. SCE adjusts the incremental Non-Incentive activity by 7.50% to add Corporate Overheads. SCE reclassifies 8.00% of this loaded activity to cost of removal and correspondingly reduces the incremental reserve balances. Finally, SCE adds 3.00% to the net of removal plant additions to reflect the estimated AFUDC required to finance construction of the projects. This is the same methodology as was used in the Second Formula Rate.

Q. Does your forecast take into account changes in accumulated depreciation?

A. Yes. Schedule 16 of the proposed Formula Rate (Exhibit No. SCE-4) includes incremental depreciation accruals on forecast plant additions. Depreciation expense is added to the Incremental Reserve balance based on a composite depreciation rate of 2.74% which was calculated based on the proposed Depreciation Rates presented in Schedule 18 of Exhibit No. SCE-4, applied to EOY Transmission Plant – ISO by FERC Account. In addition to increases attributable to depreciation expense, incremental reserve balances are reduced by forecast Cost of Removal. This is the same methodology as was used in the Second Formula Rate.

Q. Please describe how you develop the Forecast Period Incremental CWIP to be incorporated into the Incremental Forecast Period TRR.

A. SCE currently has nine projects that have been approved by the Commission for Incentive CWIP treatment. Details on the approved incentive projects including SCE's monthly capital expenditure forecast and the expected completion date(s) for each project can be found in Mr. Moon's testimony, Exhibit SCE-9. SCE's forecast of Incentive CWIP starts with recorded EOY CWIP balances. It takes the monthly capital expenditure forecast from Mr. Moon's testimony, incorporates corporate overheads using the corporate overheads loader, accumulates a monthly Incentive CWIP balance and reflects the reclassification of Incentive CWIP to Transmission Plant as projects reach their estimated completion date. The Forecast Period Incremental CWIP is presented in Schedule 10 of Exhibit No. SCE-4.

Q. Does this conclude your testimony?

A. Yes, it does.

DECLARATION

I, David C. Gunn, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 5, 2019 in Rosemead, California

David C. Gunn

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

EXHIBIT SCE-8

EXHIBIT TO THE TESTIMONY OF
MR. DAVID C. GUNN

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

Application No.:	A.16-09-
Exhibit No.:	SCE-09, Vol. 03
Witnesses:	P. Joseph A. Varvis R. White

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Results of Operations
Volume 03 – Depreciation Study

Before the

Public Utilities Commission of the State of California

Rosemead, California
September 1, 2016

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I.

INTRODUCTION

Depreciation is the means by which SCE's investors recover the costs of the fixed capital investments they have made to provide electric service to SCE's customers. Depreciation provides a mechanism for recovery of the original cost of the investment and the future cost to retire the investment over its useful life. In each GRC, SCE submits a depreciation study that presents analyses of service lives and retirement costs. In Volume 2 of SCE-09, SCE set forth its proposed depreciation expense accruals for 2018-2020. This Volume 3 of SCE-09 describes the depreciation study undertaken by SCE's in-house and outside experts.

In this rate case, unlike prior ones, SCE undertook an *actuarial* analysis to estimate life parameters for its transmission and distribution (T&D) assets. Actuarial analyses rely on aged data, not on the unaged plant records that SCE used in the past to derive its proposed depreciation expense. SCE's actuarial analysis revealed that for 18 of 20 T&D accounts, the forecast service life of many assets is the same or longer than what had been authorized in the past. When service lives are extended, depreciation expense will decrease, all other things being equal.

However, a large driver impacting depreciation expense is cost of removal. As assets age, the effect of inflation increases cost of removal. Indeed, depreciation is a major expense in large part because it includes an allocation of the original cost of fixed capital and its estimated future cost of removal. This future removal cost, called net salvage, is defined as gross salvage minus cost of removal. When cost of removal is higher than gross salvage, as is commonly experienced in the utility industry, the value is negative and results in an increase to total depreciation expense. When that increasing cost to remove is expressed as a percentage of the original cost—a computation known as the net salvage ratio, or NSR—it becomes more negative as SCE's infrastructure ages.

In the 2015 GRC, the Commission directed SCE to conduct a more detailed analysis of its cost of removal for at least five of SCE's largest plant accounts as measured by proposed depreciation expense. That rigorous analysis, known as a "per-unit" analysis, differs from the traditional way in which SCE forecasts net salvage. Section C of Chapter II describes these differences in detail, but the main point is that under a per-unit analysis, SCE divides each plant account into "sub-populations" of similar assets, determines the historical cost to remove each unit in the sub-populations, and then applies the per-unit cost to the quantities identified in the surviving plant balance. SCE uses the surviving plant balance (*i.e.*, the mix of assets on SCE's books *today*) as the "window" into what future costs of removal will be, given the projected timing of the assets' retirement. This work is detailed and rigorous, and meets the Commission's compliance directives described in Chapter II. A traditional cost of removal analysis, applied to the balance of accounts, takes a more aggregated approach and generally assumes that future removal costs and activity will mimic what SCE experienced in the past. Both are accepted methods of forecasting the cost of removal, but the per-unit analysis is more detailed and labor-intensive.

The study results confirmed that SCE's NSRs are increasingly negative. That fact is not surprising given SCE's recorded history and the many other drivers SCE discusses in Section D of Chapter II. In fact, applying the results of the study would result in an estimated increase in depreciation expense of $963 million. However, SCE is not requesting to recover that sum over this GRC cycle given the resulting impact it would have on customers' retail rates. Rather, for reasons described in Section B of Chapter II, SCE elects to moderate its proposal in service of a public policy principle on which the Commission has relied before in the depreciation context—"gradualism." The idea is to spread the increases in depreciation expense over time to mitigate the immediate rate impact on customers. Thus, for T&D accounts where SCE's depreciation study results in an increase greater than 25% of currently authorized NSRs, SCE proposes to cap the increase at 25%. The result of applying this cap is to reduce SCE's proposal to $71 million above currently authorized, $892 million less than what the study results justify, as shown in Figure I-1 below.

A. Organization of Testimony

This chapter summarizes SCE's depreciation proposal comparing the "full" (un-tempered) empirical study results with SCE's moderated proposal. Section D of this chapter shows average life and NSR values for all accounts.

Sections A through C of Chapter II address the Commission's four compliance directives from SCE's 2015 GRC, which required additional quantitative detail to support SCE's net salvage proposals.[1] Section D of the same chapter offers qualitative reasons for SCE's increasingly negative net salvage rates.

Chapter III sets forth the results of SCE's depreciation study, based on plant assets as of December 31, 2015, separated into: (1) a life and net salvage analysis of Transmission and Distribution (T&D) assets, undertaken by SCE's outside expert (Section A of Chapter III); and (2) a life and net

[1] The compliance directives are also addressed in Chapter III, Section A.3.

salvage analysis of Generation assets, plus General and Intangible (G&I) assets, undertaken by SCE's in-house expert (Section B of Chapter III).

B. SCE's Depreciation Proposals

As shown in Table I-1, SCE's total proposed depreciation expense resulting from the study's revised parameters (using the moderated approach) is approximately five percent higher than recorded 2015 depreciation expense using the 2015 GRC-authorized depreciation rates.

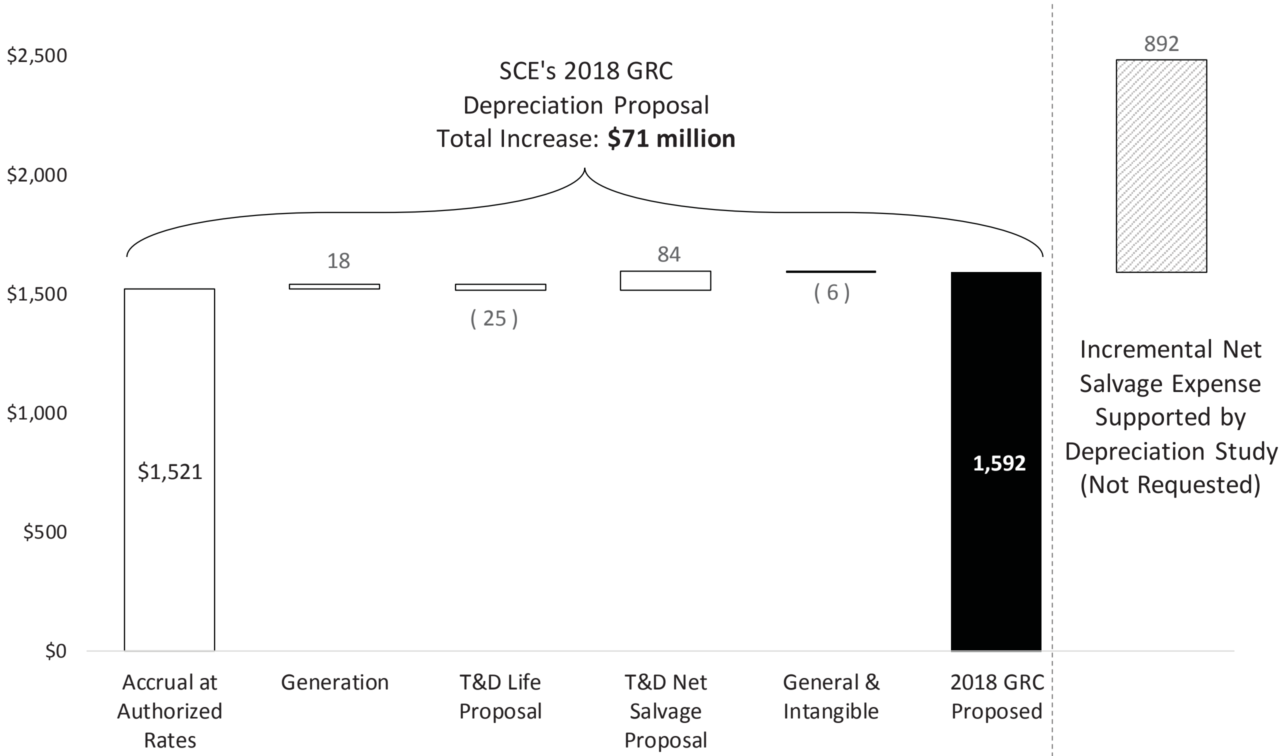
Table I-1[2]
Depreciation Expense Proposal

Line No.	Item	Depreciation Expense (Nominal $M)	% Change from 2015 Recorded (Line 1)
1.	Recorded 2015 Depreciation Expense at Authorized Depreciation Rates (from 2015 GRC)	$1,656	
2.	Change due to 2016-2018 Plant Growth at Authorized Depreciation Rates	$266	*16.1%*
3a.	Change due to proposed Depreciation Rates applied to Year-End 2015 Recorded Plant	*$71*	*4.3%*
3b.	Change due to Proposed Depreciation Rates applied to 2018 Forecast Plant	*$10*	*0.6%*
3.	Total Change due to Depreciation Study (Sum of 3a and 3b)	**$81**	***4.9%***
4.	Proposed Test Year 2018 Depreciation Expense (Sum of Lines 1,2, and 3)	$2,003	*21.0%*

SCE's depreciation rate proposals (Line 3a above) can be separated into major functional categories as shown in Figure I-1 below.

2 Refer to WP SCE-09 Vol. 03, Book A, pp. 1-20 (Depreciation Rate Proposals).

Figure I-1[3]
Impact of Proposed Depreciation Rates by Class of Plant
(Based on Year-End 2015 CPUC-Jurisdictional Plant Balances, $M)



Note: The far left bar in the figure above shows a different number ($1,521M) from Table I-1 ($1,656) for two reasons: (1) It is calculated using only year-end 2015 plant balance instead of the full year 2015 recorded plant balances; and (2) it represents CPUC-jurisdictional depreciation expense only.

The increase in generation accruals is due primarily to shorter life proposals for hydro and solar facilities (See Section B of Chapter III). For T&D, SCE proposes to extend or retain average service lives for 18 of 20 accounts, and proposes more negative NSRs for 13 of 20 T&D accounts. The small change in General & Intangible accruals is the result of SCE's proposal to recover recorded reserve deficits.

As shown in Figure I-1 above, the results of SCE's net salvage analysis support a total increase in the annual accruals for net salvage of $976 million (assuming 2.72% inflation) consisting of SCE's requested $84 million plus an additional $892 million not requested in this rate case. Section C below

[3] Because this figure is based on CPUC-jurisdictional plant balances as of Year-End 2015, it does not include the impact of forecast plant additions from 2016-2018. The estimated impact of these forecast additions is shown in Line 2 of Table I-1 above.

discusses SCE's approach to moderating its T&D net salvage expense proposals to the requested $84 million.

C. Application of Gradualism Principle to SCE's Proposal

The results of the more rigorous per-unit net salvage analysis required as part of the Commission's directives from the 2015 GRC (see Chapter II), together with a forecast of the timing of retirements,[4] supports increasing SCE's annual accruals for T&D net salvage by $976 million above currently authorized levels. This depreciation proposal "as is" would translate into a large revenue requirement increase if the Commission were to adopt it. Given the magnitude of the impact this proposal would have on retail rates, SCE requests only $84 million for T&D net salvage accruals.

SCE chooses to "temper" its depreciation request in light of the Commission's recognition that while a utility could substantiate large depreciation expense requests through "empirical analysis of cost trends,"[5] more moderated rates may be in the public interest for reasons unrelated to empirical analyses. The Commission discussed this principle—known as "gradualism"—relatively recently in its Decision Authorizing Pacific Gas and Electric Company's (PG&E's) General Rate Case Revenue Requirement for 2014-2016, D.14-08-032, where it approved increased negative net salvage rates relative to PG&E's then-current rates "but at a reduced level relative to PG&E's forecasts to mitigate ratepayer impacts and to reflect the principle of gradualism."[6]

Specifically, the Commission concluded that for all asset accounts in which net salvage amounts were contested, it would adopt no more than 25% of the estimated net increase from current rates that would otherwise result from applying PG&E's net negative salvage rates (*e.g.*, if the previously approved NSR was -50% and PG&E requested -100%, the Commission adopted an NSR no more negative than -62.5%). The Commission concluded that 25% of the difference between then-current rates and proposed rates "gives some credence to the empirical methods used by PG&E while declining

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4 To estimate the timing of retirements, SCE used the average retirement life and dispersion curves determined through its actuarial analyses, and then applied a 2.72% capital escalation assumption to determine forecast net salvage. For an explanation about the basis of the inflation assumption, refer to WP SCE-09 Vol. 03, Book A, p. 24 (Capital Escalation).

5 D.14-08-032, p. 596.

6 *Id*., p. 11.

to pass along the full amount of PG&E's forecasted increase in negative salvage rates to current ratepayers."[7]

SCE's gradualism proposal in this proceeding uses a different formula than the one the Commission applied in PG&E's 2014 GRC Decision because SCE proposes to cap increases at 25% more than currently authorized NSRs rather than proposing an increase equal to 25% of the difference between proposed and authorized NSRs.[8] See Table I-2, below, for a summary of SCE's capping proposal (which was applied only to the accounts with gray highlights given that the study results would have increased the NSRs by more than 25% from authorized rates).

[7] *Id.*, p. 602. In SCE's 2015 GRC, the Commission relied on its rationale from the PG&E case, stating that "[c]onsistent with the logic of gradualism that we applied to PG&E," it adopted a negative net salvage rate for Account 364 of -210% instead of the -225% that SCE had requested. D.15-11-021, p. 421. Similarly, for Account 369, SCE proposed an increase from -85% to -125%. "Consistent with gradualism," and for other reasons, the Commission adopted an increase to -100%. *Id.*, p. 425. In SCE's 2009 GRC, the Commission did not refer to "gradualism" as a doctrine but nonetheless tempered SCE's otherwise reasonable removal cost estimates "because of economic difficulties facing ratepayers." D.14-08-032, p. 599 (citing D.09-03-025, pp. 179-180).

[8] SCE's proposal, using the same calculation method as the Commission applied in the 2014 PG&E Decision, is equal to roughly 10% of the difference between currently authorized NSRs T&D accounts and what SCE's study results would justify.

Table I-2
SCE's Proposed Net Salvage Ratios for T&D Accounts

FERC Acct	Description	2015 GRC Authorized	Study Results	25% Above Authorized	SCE's NSR Proposals
A	B	C	D	E=C*1.25	G=Lesser of D or E
Transmission Plant					
352	Structures and Improvements	35%	35%	44%	35%
353	Station Equipment	15%	10%	19%	10%
354*	Towers and Fixtures	60%	185%	75%	75%
355*	Poles and Fixtures	72%	499%	90%	90%
356*	Overhead Conductors and Devices	80%	210%	100%	100%
357	Underground Conduit	0%	0%	0%	0%
358	Underground Conductor and Devices	15%	25%	19%	19%
359	Roads and Trails	0%	0%	0%	0%
Distribution Plant					
361	Structures and Improvements	25%	30%	31%	30%
362	Station Equipment	25%	50%	31%	31%
364*	Poles, Towers and Fixtures	210%	488%	263%	263%
365*	Overhead Conductors and Devices	115%	538%	144%	144%
366*	Underground Conduit	30%	401%	38%	38%
367*	Underground Conductor and Devices	60%	261%	75%	75%
368*	Line Transformers	20%	47%	25%	25%
369*	Services	100%	387%	125%	125%
370	Meters	5%	0%	6%	0%
373	Streetlights	30%	100%	38%	38%

* *Used a per-unit analysis to arrive at proposed net salvage rates*

The moderated NSRs, taken together with the balance of SCE's depreciation proposal, result in a total depreciation request that is less than 5 percent above what the Commission authorized for SCE in the 2015 GRC Decision.

SCE has weighed the balance between setting rates in this GRC based on cost-of-service principles, on the one hand, and being mindful of customer rate impacts, on the other. SCE also acknowledges errors inherent in any forecast of lives and removal costs of long-lived assets given the many variables that will eventually bear on the final costs. SCE recognizes the Commission's statement that one must "be cautious in making large changes in estimates of service lives and net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect."[9] Indeed, the premise of SCE's per-unit analysis is that one can take the per-unit historical

[9] D.14-08-032, p. 598.

cost to remove assets, and apply that per-unit cost to the *quantities* of assets in the surviving plant balance to obtain a reasonable forecast of the cost to remove the assets given projections about the timing of the assets' retirements. A key assumption in this analysis is the per-unit cost to retire each asset. While the proposals presented in SCE's depreciation study substantiate sound estimates of the future costs to retire, SCE does not overlook that future rate cases will provide updates to SCE's recorded experience that will further refine the expectations of future net salvage. That is, in future rate cases, SCE will have the ability to take its then-surviving plant balances to even better refine its projections about the future in light of then-available conclusions about historical costs-per-unit. By moderating SCE's depreciation expense, the Commission will make progress towards SCE's current estimate of forecast net salvage while permitting the Company in future rate cases to rely on additional data to refine its forecasts.

D. Summary Tables

Table I-3, Table I-4, and Table I-5 below summarize the life and net salvage parameters resulting from the analyses described in the chapters below.

Table I-3[10]
Summary of SCE's Request for Depreciation Parameters - Transmission and Distribution

FERC Account	Description	Net Salvage Rates			Curves and Lives			Depreciation Rates		
		Auth.	Prop.	Change	Auth.	Prop.	Change	Auth.	Prop.	Change
A	B	C	D	E=D-C	F	G	H=G-F	I	J	K=J-I
Transmission										
352	Structures and Improvements	-35%	-35%		S 3.0 55	L 1.0 55		2.53%	2.40%	*-0.13%*
353	Station Equipment	-15%	-10%	*5%*	R 0.5 45	L 0.5 40	*-5*	2.66%	2.84%	*0.18%*
354	Towers and Fixtures	-60%	-75%	*-15%*	R 5.0 65	R 5.0 65		2.30%	2.73%	*0.43%*
355	Poles and Fixtures	-72%	-90%	*-18%*	R 0.5 50	SC 65	*15*	3.43%	2.84%	*-0.59%*
356	Overhead Conductors & Devices	-80%	-100%	*-20%*	R 3.0 61	R 3.0 61		2.63%	3.24%	*0.61%*
357	Underground Conduit	0%	0%		R 3.0 55	R 3.0 55		1.73%	1.73%	*0.00%*
358	Underground Conductors & Devices	-15%	-19%	*-4%*	R 2.5 40	S 1.0 45	*5*	2.65%	2.41%	*-0.24%*
359	Roads and Trails	0%	0%		SQ 60	R 5.0 60		1.52%	1.65%	*0.13%*
Distribution										
361	Structures and Improvements	-25%	-30%	*-5%*	R 2.5 42	L 0.5 50	*8*	3.04%	2.39%	*-0.65%*
362	Station Equipment	-25%	-31%	*-6%*	R 1.5 45	L 0.5 65	*20*	3.13%	2.01%	*-1.12%*
364	Poles, Towers and Fixtures	-210%	-263%	*-53%*	L 0.5 47	R 1.0 55	*8*	7.04%	7.09%	*0.05%*
365	Overhead Conductors & Devices	-115%	-144%	*-29%*	R 0.5 45	R 0.5 55	*10*	4.87%	4.49%	*-0.38%*
366	Underground Conduit	-30%	-38%	*-8%*	R 3.0 59	R 3.0 59		2.22%	2.27%	*0.05%*
367	Underground Conductors & Devices	-60%	-75%	*-15%*	R 0.5 45	R 1.5 43	*-2*	2.98%	3.94%	*0.96%*
368	Line Transformers	-20%	-25%	*-5%*	R 1.0 33	S 1.5 33		3.93%	4.57%	*0.64%*
369	Services	-100%	-125%	*-25%*	R 1.5 45	R 1.5 45		4.34%	5.04%	*0.70%*
370	Meters	-5%	0%	*5%*	R 3.0 20	R 3.0 20		5.30%	5.61%	*0.31%*
373	Street Lighting & Signal Systems	-30%	-38%	*-8%*	L 0.5 40	L 1.0 48	*8*	3.10%	3.00%	*-0.10%*
General Buildings										
390	Structures & Improvements	-10%	-10%	*0%*	R 3.0 38	R 0.5 45	*7*	2.74%	2.08%	*-0.66%*

Used a Per-Unit Analysis to analyze Net Salvage

Moderated as discussed in Chapter 1, Section C

Proposed Retention of Currently Authorized Lives

10 Refer to WP SCE-09 Vol. 03, Book A, pp. 5-20 (Rate Determination Schedule).

Table I-4[11]
Summary of SCE's Request for Book Depreciation
Generation Plant

Generation Facility	Life Spans		Net Salvage	
	Auth.	Prop.	Auth.	Prop.
A	B	C	D	E
Nuclear Production - Palo Verde	30.5 yrs.	28.0 yrs.	Covered under NDCTP	
Hydro Production	26.0 yrs.	19.9 yrs.	$79.3 M	$95.3 M
Other Production				
Pebbly Beach	45 yrs.	25 yrs.	$6.6 M	-
Mountainview	35 yrs.	35 yrs.	$16.3 M	$18.5 M
Peakers	35 yrs.	35 yrs.	$12.1 M	$15.1 M
Solar Photovoltaic	25 yrs.	20 yrs.	$81.9 M	$80.9 M
Fuel Cells	10 yrs.	10 yrs.	-	-
Energy Storage	N/A	10 yrs.	N/A	-

Table I-5[12]
Summary of SCE's Request for Book Depreciation
General and Intangible Plant

FERC Account	Description	Lives		Depreciation Rates	
		Auth.	Prop.	Auth.	Prop.
A	B	C	D	E	F
General Plant					
389.2	Easements	60	60	1.67%	1.67%
391.1	Office Furniture	20	20	5.00%	5.00%
391.2	Personal Computers	5	5	20.00%	20.00%
391.3	Mainframe Computers	5	5	20.00%	20.00%
391.4	DDSMS-Security Monitoring System	Various	Various	12.90%	9.84%
391.5	Office Equipment	5	5	20.00%	20.00%
391.6	Duplicating Equipment	5	5	20.00%	20.00%
391.7	PC Software	5	5	20.00%	20.00%
393	Stores Equipment	20	20	5.00%	5.00%
394	Tools & Work Equipment	10	10	10.00%	10.00%
395	Laboratory Equipment	15	15	6.67%	6.67%
397	Telecommunication Equipment	Various	Various	9.77%	11.65%
398	Misc. Power Plant Equipment	20	20	5.00%	5.00%
Intangible Plant					
302.020	Hydro Relicensing	Various	Various	2.52%	2.47%
303.640	Radio Frequency	40	40	2.50%	2.50%
302.050	Miscellaneous Intangibles	20	20	5.00%	5.00%
303.105	Capitalized Software - 5 year	5	5	20.00%	20.00%
303.707	Capitalized Software - 7 year	7	7	14.29%	14.29%
303.210	Capitalized Software - 10 year	10	10	10.00%	10.00%
303.315	Capitalized Software - 15 year	15	15	6.67%	6.67%

[11] *Id.*, pp. 5-7.
[12] *Id.,* pp. 9-12.

II.

COMMISSION DIRECTIVES FROM SCE'S 2015 GRC DECISION

In the 2015 GRC Decision, the Commission gave four directives for SCE's net salvage proposals in this 2018 GRC proceeding. Most of the remainder of this chapter explains SCE's approach to meeting each of the directives. Section D addresses SCE's experience with increasingly negative net salvage rates (this testimony refers to "higher" net salvage rates, for simplicity's sake) and demonstrates how the advancing age of SCE's infrastructure and the increasing urbanization within its service territory has contributed to more negative NSRs.

A. The Four Directives Established in the 2015 GRC Decision

Ordering Paragraph 9 of the 2015 GRC Decision required SCE to "provide considerably more detail in support of its net salvage proposals for at least five of the largest accounts, as measured by proposed annual depreciation expense" including at least the following:[13]

The First Directive

> "A quantitative discussion of historical and anticipated future Cost of Removal (COR) on a per unit basis for the large (greater than 15% as measured by portion of plant balance) asset classes in the account. This discussion should identify and explain the key factors in changing or maintaining the per-unit COR."

The Second Directive

> "A quantitative discussion of historical and anticipated future retirement mix (i.e., retirements among different asset classes), identifying and explaining the key factors in changing or maintaining this mix."

The Third Directive

> "A quantitative discussion of the life of assets and original cost of assets being retired, in relation to the COR, on both a historical and anticipated future basis. This discussion should be integrated with and/or cross-reference the proposal for life characteristics."

The Fourth Directive

> "An account-specific discussion of the process for allocating costs to COR."[14]

The per-unit analysis required by the Commission involves substantially more work than a "traditional" net salvage analysis that is typically performed by the industry (as described in Standard Practice U-4).[15]

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[13] D.15-11-021, Ordering Paragraph 9, p. 554.
[14] *Id*., pp. 554-555.
[15] For the purpose of this testimony, the term "traditional approach" will be used to describe Standard U-4.

Table II-6, below, summarizes the differences at a high level, and Sections B and C of this chapter goes into more detail.

Table II-6
Summary of Difference Between Per-Unit Analysis and Traditional Approach

	Compliance Directive from 2015 GRC	Per-Unit Analysis (Required by 2015 GRC Decision)	Traditional Approach (As Established in Standard Practice U-4)
1.	**Perform a per-unit COR analysis**	Separate account into sub-populations (*e.g*., account 365 conductor vs. account 365 switches) and calculate a per-unit COR. Math: Historical cost to retire assets divided by *quantities* of property units being retired within each subpopulation.	Calculate NSR at the account level of detail (e.g., account 365). Math: Historical cost to retire assets divided by *original cost* of assets retiring.
2.	**Discuss Whether Retirement Mix Will Change Or Stay The Same**	Apply the per-unit cost estimate results to surviving plant balance assuming that the future retirement mix will be consistent with the current plant balance.	Assumes that the future retirement mix will mimic SCE's recorded experience.
3.	**Integrate Salvage Analysis with Life Analysis**	Utilize original cost of current plant-in-service and results of the life analysis to estimate timing and cost of future retirements.	Assume that the future average age of retirements, and the inflation embedded in the cost of removal, will both mimic recorded activity.
4.	**Discuss COR Allocation**	Provide account-specific discussion for the process for assigning costs to cost of removal (versus install).	

B. <u>SCE's Approach to Addressing the Compliance Directives from the 2015 GRC Decision</u>

To comply with the directives from the 2015 GRC Decision, SCE performed a per-unit analysis for "at least five of the largest accounts, as measured by [the] proposed annual depreciation expense." As shown in Table II-7, below, the five largest accounts under that definition are distribution accounts 364, 365, 367, 368, and 369.[16]

SCE performed a per-unit analysis on nine T&D accounts, which comprise 85% of the total COR expense proposed. Apart from the five largest accounts, SCE performed a per-unit analysis on another distribution line account, Account 366, which is the only remaining account in the series 364-369 (covering distribution line circuits). In addition, SCE performed a per-unit analysis for Account 354 (Transmission Towers) because a traditional analysis produced anomalous estimates of future net salvage rates (upwards of -800%) resulting from the removal of very old towers with a high cost to retire. SCE also selected accounts 355, 356, and 366 (Transmission Poles, Transmission Overhead

[16] The same five T&D accounts represented the top five accounts (measured by proposed depreciation expense) in the 2015 GRC.

Conductor, and Distribution Underground Conduit respectively) given their similarity to corresponding distribution account assets for which SCE conducted a per-unit analysis.

The Commission's directives from the 2015 GRC Decision stand alone. However, in the course of complying with those directives, SCE is indirectly addressing related directives from SCE's 2012 GRC Decision (D.12-11-051, pp. 683-686). In the 2012 GRC decision, the Commission asked SCE to: (1) provide more information about its cost of removal estimates; and (2) to "review its allocation practices to be sure that all installation-related costs are booked to Plant-in-Service," instead of to cost of removal.[17] Both decisions request additional information substantiating removal costs and reviewing SCE's cost allocation. The primary distinction is that the 2015 GRC Decision required SCE to analyze its largest accounts by the proposed depreciation expense, whereas the 2012 GRC Decision instead required that SCE select its largest accounts using industry comparisons.

[17] D.12-11-051, p. 683.

Table II-7
T&D Accounts Ranked by Proposed Annual Depreciation Expense
(Based on CPUC-Jurisdictional Depreciation Expense ($M))

FERC Account	Description	Proposed Depr. Exp.	Rank
Transmission Plant			
352	Structures and Improvements	5,101	*15*
353	Station Equipment	62,978	*6*
354	Towers and Fixtures	2,603	*16*
355	Poles and Fixtures	19,820	*11*
356	Overhead Conductors & Devices	7,856	*13*
357	Underground Conduit	1,053	*17*
358	Underground Conductors & Devices	6,160	*14*
359	Roads and Trails	114	*18*
Distribution Plant			
361	Structures and Improvements	13,783	*12*
362	Station Equipment	45,110	*8*
364	Poles, Towers and Fixtures	174,654	***2***
365	Overhead Conductors & Devices	64,341	***5***
366	Underground Conduit	44,209	*9*
367	Underground Conductors & Devices	218,724	***1***
368	Line Transformers	160,345	***3***
369	Services	65,591	***4***
370	Meters	50,205	*7*
373	Streetlights	26,163	*10*
Total		968,810	

Proposals based on results of Per-Unit Analysis ($758M or 78% of Total Expense)

1. The First Directive – Per Unit Net Salvage Analysis

The per-unit net salvage analysis segments each FERC plant account into large subpopulations (*i.e.*, dollar value of assets representing more than 15% of the total account balance).[18] To calculate the average per-unit cost to remove, SCE divided the net salvage dollars incurred by the quantity of units retired for each of the identified subpopulations. For example, Account 368—

[18] In the first compliance directive from the 2015 GRC Decision, the Commission referred to "large . . . asset classes in the account" as measured by 15% or more of the portion of plant balance. D.15-11-021, p. 398. SCE uses the term "subpopulation" to refer to those large asset classes within each FERC account.

Distribution Line Transformers—consists of three major subpopulations; overhead (OH) transformers, underground (UG) transformers, and fuseholders. For each subpopulation, SCE divided the net salvage incurred from 2009-2015[19] by the quantity of units retired, as shown in Figure II-3, below. This per-unit cost to remove each asset formed one part of the basis for forecasting SCE's expected future net salvage proposals presented in this GRC.

a) Traditional Approaches to Analyzing Historical and Future Net Salvage

Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals ("U-4," or "Standard Practice U-4"), "sets forth various factors influencing the determination of depreciation accruals and describes methods of calculating these accruals"[20] with the purpose of assisting "the Commission staff in determining proper depreciation expenses."[21] Although over 50 years old, Standard Practice U-4 represents conventional utility depreciation practices. The depreciation rates proposed in this study are consistent with the standard practices described in U-4. In addition, SCE conducted a more rigorous per-unit analysis for nine T&D accounts in response to the Commission's directives from the 2015 GRC.

To meet requirements set forth in U-4, SCE uses different approaches to estimate NSRs based on the plant's retirement characteristics and recorded experience. Broadly speaking, SCE's net salvage study analyzes mass property differently than life-span property and other non-mass plant accounts. Mass property accounts (*e.g.,* transmission and distribution plant accounts) are those that have a significant number of property units which are generally retired separately. Life-span property refers to accounts which are comprised of a few major units which individually are expected to retire at a single point in time (*e.g.*, generating plants).

Mass property plant accounts, such as T&D, can contain a significant number of components and generally experience large numbers of retirement transactions under a diverse number of retirement circumstances. The large number of retirement units and retirement occurrences for mass property generally necessitate an analysis of *aggregate* historical NSRs and per-unit costs. To accomplish this, Standard Practice U-4 describes how to estimate future net salvage rates using the

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[19] This period contains detailed net salvage data by CPR, available in PowerPlan, SCE's capital system of record. Net salvage data prior to this period is maintained at the FERC prime account level only.

[20] Standard Practice U-4 is available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M042/K177/42177433.PDF and includes methods to analyze net salvage.

[21] *Id.*, p. 6.

experienced ratios of net salvage, gross salvage, and removal cost (in today's dollars) as a percent of the original installed costs (in older dollars) of retirements. The average net salvage rate by FERC account is then applied to the total plant balance to determine the estimated future net salvage amount, barring any adjustments. Understanding the inputs involved in the calculation and the calculation itself is important to interpreting the resulting NSRs. The calculations are as follows:

Figure II-2
Computing NSRs Under the Traditional Approach

$$\text{Net Salvage \%} = \text{Gross Salvage \%} - \text{Removal Cost \%}$$

$$\frac{\text{Net Salvage (\$)}}{\text{Retirements (\$)}} = \frac{\text{Gross Salvage (\$)}}{\text{Retirements (\$)}} - \frac{\text{Removal Cost (\$)}}{\text{Retirements (\$)}}$$

b) Comparing the Differences Between Calculating Net Salvage Ratios Using a Traditional Analysis Versus Per-Unit Analysis

The first and most important way that a per-unit analysis differs from the traditional analysis is that the NSRs are computed using the original cost of the *surviving* plant balance (*i.e.*, the current plant balance), as opposed to a traditional analysis' use of the original cost of the plant that has already *retired*. That is, a traditional net salvage analysis examines the *historical* NSRs as the principal factor used to estimate *future* NSRs. By contrast, the per-unit analysis takes historical per unit costs and applies them to surviving plant *quantities* to project future removal costs given projections (from the life analysis) of when assets are expected to retire. The traditional approach implicitly assumes that factors such as the age of retirements, changes in SCE's operating environment, levels of inflation and other factors will, in the future, be the same as they were in the past. By contrast, a per-unit analysis develops forward-looking estimates of net salvage by relying on recorded costs, surviving plant balances, and assumptions about the timing of future retirements.

An illustration of SCE's approach to the per-unit analysis computation is instructive, especially compared to the calculation in Figure II-2, above. First, the net salvage cost per-unit is calculated by summing seven years' worth of recorded history—in both dollars used to remove assets, and quantities of assets removed—to arrive at a per-unit net salvage value by sub-population:

Figure II-3
Calculation of Per-Unit Net Salvage Costs
(Recorded 2009-2015 values for Account 368 – Line Transformers)

$$\text{Per-Unit Net Salvage} = \frac{\text{Net Salvage (\$)}}{\text{Quantity Retired}}$$

		Overhead Transformer	Underground Transformer	Fuseholder	Others
Per-Unit Net Salvage	=	$79,500,742 / 141,838	$78,642,058 / 53,904	$44,409,667 / 275,472	$19,071,340 / 19,862
	=	$560.50	$1,458.93	$161.21	$960.19

Next, the per-unit cost derived above is applied to a forecast using anticipated rates of inflation, as opposed to inflation experienced in the past. A simplified (no-inflation) calculation of future net salvage is shown in Figure II-4, as it shows the per-unit net salvage from Figure II-3 multiplied by the year-end 2015 surviving quantities (the study date). The resulting value is equivalent to an estimate of the cost to remove all of the assets in Account 368 as of the study date.

Figure II-4 [22]
Calculation of Future Net Salvage Using a Per-Unit Methodology
(for Account 368 – Line Transformers; excluding future inflation)

$$\text{Future Net Salvage} = \text{Per-Unit NS} \times \text{Per-Unit Surviving Quantity}$$

		Overhead Transformer		Underground Transformer		Fuseholder		Others
Future Net Salvage	=	$560.50 x 456,611	+	$1,458.93 x 259,299	+	$161.21 x 1,400,640	+	$960.19 x 62,788
$920,320,858	=	$255,932,428		$378,298,499		$225,801,375		$60,288,556

This forecast of future net salvage can be divided by the costs of assets currently serving customers (the denominator, or surviving plant balance) to arrive at an estimated future NSR. This no-inflation estimate of the future NSR is shown in Figure II-5 below.

22 Refer to WP SCE-09 Vol. 03, Book A, pp. 21-24 (Per-Unit Calculations).

Figure II-5[23]
Derivation of Future Net Salvage Rate Under a Per-Unit Analysis
(for Account 368 – Line Transformers; excluding future inflation)

$$\text{Future Net Salvage Rate} = \frac{\text{Future Net Salvage}}{\text{Surviving Plant}}$$

$$\mathit{26.7\%} = \frac{\$920,320,858}{\$3,450,870,284}$$

To summarize, a per-unit analysis estimates future net salvage by: 1) establishing a per-unit cost to retire each asset, 2) applying results of the life analysis to estimate when these costs will be incurred, and 3) dividing this forecast net salvage by the surviving plant balance. See Figure II-6 below for a simplified comparison of the differences.

Figure II-6
Simplified Comparison of Traditional Analysis vs. Per-Unit Analysis

Traditional Analysis

$$\textbf{Future Net Salvage Rate} = \frac{\text{Net Salvage Incurred}}{\textit{Cost}\ \text{Retired}}$$

Per-Unit Analysis

$$\text{Per-Unit Net Salvage} = \frac{\text{Net Salvage Incurred}}{\textit{Quantity}\ \text{Retired}}$$

$$\text{Future Net Salvage} = \text{Per-Unit Net Salvage} \times \text{Surviving Quantity}^{1}$$

$$\textbf{Future Net Salvage Rate} = \frac{\text{Future Net Salvage}}{\text{Surviving Plant}^{2}}$$

1. Multiplying by surviving quantity produces forward-looking estimates of net salvage (in more complex examples, the timing of removal and level of inflation will change the per unit net salvage value).

2. Using the surviving plant balance is representative of the future retirement mix.

2. The Second Directive – Retirement Mix

The second directive, requiring a discussion of the historical and future retirement mix, has been addressed by separating the original directive into two sub-directives (1) an analysis and

[23] *Id.*

discussion of the historical retirements, and (2) a discussion of the expected future retirement mix. The per-unit analysis described above complies with the first sub-directive because it requires review of the historical mix of retirements to determine an average per-unit cost to retire. To address the second sub-directive, SCE assumes that the future retirement mix will be consistent with the asset mix in the surviving plant balance as of year-end 2015. (In future rate cases, when the retirement mix changes, the forecast NSR will change accordingly.)

Analyzing the account by subpopulation achieves a more detailed "weighting" than looking at the account-based retirement mix in the aggregate. That is, the traditional approach focuses solely on the backward-looking ratios, which are used to estimate *future* net salvage. The blunt assumption underlying this approach is that the mixture of asset retirements in the past is representative of what one could expect in the future without regard to the composition of the then-current plant balance. Under the per-unit approach, by contrast, one focus is on the *surviving* plant balance, which offers a "snapshot" in real time that forms the basis for estimating the future mix of retirements. In determining its proposed depreciation expense, SCE did not identify or rely on factors that would cause it to modify the future retirement mix relative to the mix that currently exists in its plant accounts. Should factors in the future modify the retirement mix, the surviving plant balances examined at the relevant time will integrate and reflect those changes.

3. The Third Directive – The Age of Retirements and Integration of Salvage and Life Analyses

The third directive requires SCE to provide a quantitative discussion of the life of assets and original cost of assets being retired in relation to the cost of removal. This directive has been addressed by separating the original directive into two sub-directives requiring (1) a discussion of the age of retirements *experienced* and (2) a forecast of the *future* age of retirements given the results of the life analysis. The Commission intended this directive to "integrate" the life analysis with the COR analysis: "This [COR] discussion should be integrated with and/or cross-reference the proposal for life characteristics."[24] The only way to properly integrate both prongs of the analysis is to factor in the impact of the *passage of time*, or inflation, on the per-unit costs. To address this directive, SCE has provided the average age and original cost of assets retired, together with a forecast of future retirements

[24] D.15-11-021, p. 398 (see also Ordering Paragraph 9.i., pp. 554-555).

using the results of the life analysis. SCE's forecasts are derived by integrating the historical (per-unit) cost to remove each asset with the forecast retirements from the life analysis.

4. The Fourth Directive – Process for Assigning Costs

In compliance with the fourth directive from the 2015 GRC Decision—requiring SCE to provide an "account-specific discussion of the process for allocating costs to COR" for at least five of the largest accounts[25] — Section C below describes in detail SCE's process for allocating a portion of total work order costs to cost of removal.

C. Process for Assigning Costs to Installation and Removal (The Fourth Directive)

The 2015 GRC Decision requested an "account-specific" discussion of the process for allocating costs to removal. For every capital project SCE undertakes, one or more work orders is created and populated with a Unit Estimate (UE) in PowerPlan, which is SCE's fixed asset accounting software system. UEs are comprised of *property* descriptions, otherwise known as continuous property records (CPRs), and *activity* descriptions. An example of a CPR is 364.330 for a distribution wood pole the "364" refers to FERC plant account 364 Distribution Poles, and the ".330" suffix refers to an SCE-specific retirement unit, in this case, a solely-owned wood pole.

The activity description of a UE is used to denote whether the activity undertaken within each work order involves: Installation of a new asset, Removal of an existing asset, or related Expense (I/R/E).[26] For each project, SCE personnel will populate a UE with the CPR and activity types that are specific to the project that they are estimating. (Note that capital material costs are assigned to Install, whereas, labor costs are assigned to I/R/E.)

UEs originate from two different "categories" of capital projects, each of which broadly uses a different cost assignment methodology. The first category is relevant to bulk-power transmission, substation, and generation-related projects, which combined account for approximately 15% of SCE's total 2016-2020 forecast cost of removal in this rate case. In general, the assets in this category are booked to all plant accounts other than Accounts 364-373, and the process for allocating costs is described in subsection II.C.1, "Project-Specific Estimating" below.

The second category is relevant to distribution and sub-transmission line assets (*e.g.*, poles, conductors, streetlights, etc.), which together account for the majority (approximately 85%) of SCE's

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[25] *Id.*

[26] For this cost assignment description, the "expense" category is considered a non-capitalized activity but is included here for completeness.

total 2016-2020 forecast COR in this rate case. At a high level, the assets in this second category (sometimes referred to as "mass plant" assets) are booked to Accounts 364 to 373, and the process for assigning costs is described in subsection II.C.2., "Design Manager (DM) Estimating" below.

1. Project-Specific Estimating (Bulk-Power Transmission, Substation, and Generation/Other)

For project-specific estimating, SCE personnel create a detailed cost estimate for each of the activities required at the outset of each job. The cost estimate reflects the total estimated costs of *installation* separate from the total estimated costs of *removal*.

a) Bulk Power Transmission and Substation (Accounts 350-359 and 362)

For bulk power transmission and substation estimates,[27] engineers and technical experts use the Scope and Cost Management Tool (SCMT) to document, track, and communicate the scope for each project. Cost estimators then complete the costs for each project identifying and separating the installation, removal and expense activities. They assign CPR accounts that serve as the basis for creating the UEs that will ultimately be uploaded into the PowerPlan system.

For example, a capital project to replace a bulk power (*e.g.*, 500/220 kV) transformer begins when the estimator develops a specific cost estimate by itemizing the scope of major activities (*e.g.*, removing the old transformer, trench cover, power/control cable, conduits, etc. and then installing the new equipment).[28] The installation and removal activities are separately identified by hours required to install and/or remove the particular assets. In other words, there is a specific estimate of the labor, equipment, and associated overheads required to remove assets, and it is not a template-based "allocation" of *total* hours required for the job. The work is also broken out by the specific classification of employee who will be performing the task and also whether or not SCE crews or contract crews will be performing the work. The details of this estimate are compiled and used to create the UE in PowerPlan that will assign the ultimate costs recorded as "installation" costs versus "removal" costs.

b) Generation and Other (Accounts 301-348, and 390-398) [29]

Generation, Information Technology, and Operational Services also use project-specific estimating. That is, a detailed scope of work is set by engineers and other technical experts. The

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[27] Examples of accounts with related assets are Accounts 350 to 359 and 362.

[28] Refer to WP SCE-09 Vol. 03, Book A, pp. 25-41 (Project-Specific Estimating) for an example of a project-specific estimate.

[29] Examples of some of these accounts are: Accounts 301 to 348 and 390 to 398.

scope of work is separated into installation and removal activities and becomes the foundation for building the UEs that are put in the PowerPlan System.

2. Design Manager (DM) Estimating (Distribution/Sub-Transmission Assets)

For the large majority of capital assets, such as distribution and some sub-transmission line assets (*e.g.*, poles, conductors, streetlights, etc.), it is impractical for SCE to use project-specific estimating every time a new capital project is undertaken. That is because in any given year, SCE will install and replace thousands of these units of property. For example, in 2015 alone, SCE replaced over 40,000 wood poles, 25,000 transformers, and 3,000 miles of conductor.[30]

To manage the high volume of work, SCE uses a template-based estimating approach to assign a capital project's total costs to Installation, Removal, and Related Expense (I/R/E). Since 2010, SCE's planners have been using Design Manager to estimate labor hours, schedule work, and price distribution and sub-transmission projects. The DM estimating approach is commonly used for emergency work, planned/routine work, and customer-driven projects including relocations, overhead/underground conversions, new service connections and meter installations. A subset of data from DM is sent to PowerPlan, and that is where SCE's allocation methodology is applied for fixed asset accounting purposes, as explained in more detail below.

a) Building a Project Estimate in DM Using Compatible Units (CUs)

A planner tasked with initiating a project (*e.g.*, a pole replacement) will open a work order and, based on the project scope (including site visits, where applicable), begin identifying Compatible Units (CUs) required to complete the job. CUs are building blocks of material and labor used to develop the distribution design and work order cost estimates. They eliminate the need for planners to manually identify and select every material component for frequently installed equipment and structures on SCE's electrical system. CUs identify the quantity and type of property needed for a project (*e.g.*, wood poles, transformers, conductors, etc.) and associated estimates of labor hours and costs. DM contains legend codes to indicate the type of activity to be performed for each asset (*i.e.*, installation vs. removal). DM incorporates the use of over 4,500 distribution CUs, to help planners build cost estimates and schedule work depending on the requirements of the job.

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[30] Refer to WP SCE-09 Vol. 03, Book D, pp. 2-40 (Per-Unit Net Salvage Analysis). Estimates are taken from per-unit analysis quantity.

b) Cost Allocation in PowerPlan

For purposes of fixed asset accounting, the CUs and legend codes from DM work orders are migrated to PowerPlan. CUs are paired with—and converted to—one of over 100 CPR accounts.[31] At this point, the CPR account consists only of quantities and types of property to be installed and, if applicable, quantities and types of property to be removed. The estimated costs and labor hours from DM are not carried over to PowerPlan. For fixed asset accounting purposes, SCE uses a "Standard Rates Table"[32] to allocate installation and removal costs relative to total project costs of individual work orders. The Standard Rates Table is also used to allocate costs among the appropriate FERC accounts.

Each CU relates to a specific, individual piece of property. For example, different CUs are used to reflect the various height, class, material, and treatment status[33] of poles. Likewise, different CUs are used to reflect the various size, voltage and even manufacturer of transformers. The number of CUs that planners use to build a UE is many times greater than the number of CPRs to which the CUs are paired in PowerPlan. The Standard Rates Table allocation is therefore performed at an aggregated level that accounts for the various types of property the CPRs encompass. The table has been in continuous use since approximately the 1970s and it sets forth allocation factors that have been studied but that have not been materially modified over the years. However, in Chapter II.C.2.c., SCE describes three studies validating that the Standard Rates Table's general allocations continue to be reasonable, if not more conservative in assigning costs to removal versus installation.

An example of how the Standard Rates Table works in PowerPlan is illustrated in the three tables below, Table II-8, Table II-9, and Table II-10. Assume that a project to replace a wood pole also requires replacing an attached streetlight fixture. The table below lists the CPRs and the associated allocation factors by activity:[34]

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[31] A CPR account is defined as the combination of a FERC plant account and a retirement unit subaccount.
[32] In prior rate cases, this "Standard Rates Table" has sometimes been referred to as "Table 34."
[33] Treatment processes vary and are used to minimize pole decay (*e.g.*, through-boring, treatments, etc.).
[34] Note that the numbers are neither dollars nor hours; they are allocation factors from the Standard Rates Table. Refer to WP SCE-09 Vol. 03, Book A, pp. 47-51 (Standard Rates Table).

Table II-8
Standard Rates Table Values

CPR Account	Description	Standard Rates Table Values				
		Install		Removal		Total
364.330	Distribution Wood Pole	1,286	+	600	=	1,886
		+		+		
373.390	Streetlight fixture	105	+	74	=	179
		=		=		
	Total	1,391	+	674	=	**2,065**

The Standard Rates Table values are not important as absolute values; they are only meaningful in relation to each other. In the example above, the value assigned to removing the pole (600) is—appropriately—much larger than the value assigned to removing the fixture (74).

Table II-9 below converts the values in the rows and columns above to percentages of the total. Comparing the values across columns shows the allocation between install and removal. Comparing the values between rows shows the allocation between CPR accounts.

Table II-9
Percent of Sum of Standard Rates

CPR Account	Description	Percent of Sum of Standard Rates Values				
		Install		Removal		Total
364.330	Distribution Wood Pole	*62%*	+	*29%*	=	*91%*
		+		+		
373.390	Streetlight fixture	*5%*	+	*4%*	=	*9%*
		=		=		
	Total	*67%*	+	*33%*	=	***100%***

Allocation between CPR Accounts

Allocation between Install and Removal for replacement project

For fixed asset accounting purposes, the percentages from the table above are applied to the allocable dollars[35] in the project's work order, as shown in Table II-10 below.

[35] Material costs are generally allocated to installation, not removal.

Table II-10
Application of Standard Rates to $1,000 of Labor

CPR Account	Description	Application of Standard Rates to $1,000 of Labor Install		Removal		Total
364.330	Distribution Wood Pole	$623	+	$290	=	$913
		+		+		
373.390	Streetlight fixture	$51	+	$36	=	$87
		=		=		
	Total	$674	+	$326	=	**$1,000**

As illustrated in Table II-8, Table II-9, and Table II-10 above, while the Standard Rates Table uses a template approach to setting allocation factors, the resulting cost assignment for each project is "customized" in several ways. First, by virtue of the planner's initial designation of CU legend codes, the *activity* for each CPR is appropriately designated as "installation" versus "removal," and these splits are specific to each project depending on the properties and quantities that are installed or removed. Second, the *quantities* of property estimated by planners are drawn into PowerPlan and trued up by the end of every project to reflect what was actually removed and installed. Third, and most importantly, as units of property and quantities change with each work order, the matrix of cost assignment becomes more complex and reflective of the work performed in that project. For example, if another CPR account were added to the illustration above, the resulting allocations would be modified to reflect the weight of each CPR account relative to the total.

3. <u>Substantiating SCE's Standard Rates Table Allocation Factors</u>

SCE has conducted three studies substantiating the results of the Standard Rates Table's installation and removal allocation factors—in 2004, 2006, and 2016. The results of these three studies are summarized in Table II-11, which shows the CORs as a percentage of total costs under the Standard Rates Table compared to the COR percentages from the 2004, 2006 and 2016 Studies. The table demonstrates that SCE's allocation practice continues to be reasonable and appropriate. In fact, the Standard Rates Table COR allocations (on which the proposals for depreciation expense are based) are the most conservative with respect to removal costs given that the study results indicate that more dollars *could* be assigned to removal using cost assignment data from field experts.

Table II-11[36]
Comparison of Cost Assignment Ratios Across Three Studies Relative to the Standard Rates Table
(Stated as Percentage of Total Cost)

FERC Account	Description	Standard Rates Table	2004 Study	2006 Study	2016 Study
Transmission Plant					
354	Towers and Fixtures		Not Applicable - Non-Mass Plant		
355	Poles and Fixtures	27.2%	30.2%	31.4%	Not Studied
356	Overhead Conductors & Devices	42.1%	56.1%	56.7%	Not Studied
Distribution Plant					
364	Poles, Towers and Fixtures	36.6%	43.0%	39.4%	46.1%
365	Overhead Conductors & Devices	34.7%	38.6%	37.1%	35.6%
366	Underground Conduit	20.0%	42.3%	41.9%	41.7%
367	Underground Conductors & Devices	34.7%	32.1%	33.7%	35.7%
368	Line Transformers	27.3%	47.4%	48.8%	41.6%
369	Services	35.5%	44.2%	44.5%	33.8%
	Weighted Average*	33.0%	38.8%	38.3%	37.5%

**Weighted by 2009-2015 Recorded Net Salvage*

a) 2004 Study [37]

In the 2004 Study, performed for the 2006 GRC, SCE assembled field operations experts who compiled and analyzed work requirements for replacement projects of various assets under many different scenarios. The 2004 Study approached replacement costs from the perspective of SCE operations and maintenance personnel who had an average of 21 years of experience working with T&D assets. These subject matter experts, who had experience performing and supervising work activities, reviewed and assessed the time and work requirements for each of several scenarios including total time spent on the project, equipment requirements, and crew size requirements. The work activities were evaluated and separated into installation and removal activities. The experts compared the results from the study to the existing allocations in the Standard Rates Table and determined that no update to the Standard Rates Table was required because the estimated costs of removal were not overstated using the existing process.

[36] The nine accounts listed on this table are the same ones for which SCE performed a per-unit analysis. Refer to WP SCE-09 Vol. 03, Book A, pp. 42-46 (Summary of Study Results).
[37] Refer to WP SCE-09 Vol. 03, Book A, pp. 52-172 (2004 Study Results).

In preparing this testimony, SCE revisited the rebuttal testimony of its outside depreciation expert from the 2015 GRC. Appendix A of the witness's rebuttal testimony was a copy of the 2004 study, and, in response to a question about the "historical documentation describing . . . the development of allocation factors used by SCE," the witness referred to the 2004 study in Appendix A (among other things) as evidence that "SCE used a very robust and detailed process to develop its allocation factors."[38] As a point of clarification, the allocation factors to which the witness referred in his testimony are not the Standard Rates Table allocations that formed the basis of SCE's depreciation request in the 2015 GRC and this 2018 GRC.[39] Rather, the witness testified to the allocation process and results from the 2004 Study together with his own observations and discussions with field personnel about cost assignment. Any lack of clarity in distinguishing between the Standard Rates Table allocations and the 2004 Study's allocations is not material as demonstrated in Table II-11, above. In fact, the results of the 2004 Study would have assigned a larger percentage of costs to removal than does the Standard Rates Table (by approximately 5%), as shown in that table.

b) <u>2006 Study</u> [40]

In 2006, SCE updated the 2004 Study in preparation for the 2009 GRC. Using a similar approach to the one utilized for the 2004 Study, SCE assembled a team of field operations experts to gather consensus estimates for labor hours for the job configuration scenarios used in the 2004 Study. The panel of study participants included overhead and underground experts from metropolitan and rural areas of SCE's service territory and others who reviewed job conditions, crew sizes, and labor hour estimates. In addition, as an enhancement to the 2004 Study, the field experts weighted the installation and removal activities by the likelihood of the scenarios' occurrence in the field. The results from the analysis were compared to the Standard Rates Table allocations, and the experts determined that if they were to update the Standard Rates Table allocations to incorporate the results of the 2006 Study, the cost of removal allocations would increase by over 5%. For this reason, and because SCE planned to implement new work planning and accounting software in 2010, SCE elected to continue using the Standard Rates Table.

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[38] 2015 GRC, SCE-26, Volume 3, p. 13. Later in the same volume, SCE's witness testified that the study in Appendix A shows that "the allocation factor <u>will</u> change based on more complex installations." *Id.*, p. 115 (emphasis in original). This was a reference to the study results, not to the way in which the Standard Rates Table allocations are applied today.

[39] The Standard Rates Table was used to assign costs for several GRCs even prior to 2015.

[40] Refer to WP SCE-09 Vol. 03, Book A, pp. 173-188 (2006 Study Results).

c) 2016 Study

(1) Background of Development of Compatible Units (CUs).

Before explaining the results of the 2016 Study, it is important to understand the development beginning in 2009 of the CUs that T&D employees use to plan, estimate, schedule and bill work. As explained in section II.C.2, above, DM incorporates the use of over 4,500 distribution CUs to assist planners with building cost estimates and scheduling work depending on the specific requirements of the job. When CUs are migrated to PowerPlan, they are mapped to CPRs and, for fixed asset accounting purposes only, the Standard Rates Table is used to allocate costs between removal and installation. The labor hours embedded in the CUs in DM are not used in the cost allocation process, but are important to facilitating the planning, scheduling, execution and closure of work orders for the T&D Operating Unit.

(2) 2009-2010 Labor Study

In 2009-2010, SCE undertook a year-long process to review and update the precursors to CUs, called "assembly kits," in preparation for integration into DM and SAP. This effort to examine CU hours was internally referred to as the "Labor Study," and it leveraged the results of the 2004 and 2006 Studies described above. The participants in the Labor Study—including construction managers and supervisors, foremen, trouble men, and standards and engineering teams from across SCE's service territory[41] — examined over 4,500 CUs of distribution assets and modified 1,800 of them.[42] The purpose was not to modify CUs for depreciation plant accounting purposes; rather, the intent of the study was to refine the "building blocks" of SCE's thousands of work orders (CUs) to improve planning, crew scheduling, estimating and pricing jobs and work order closure processes.

For three to four months of eight-hour days, the teams went line-by-line through SCE's old Material Management System (the old mainframe system in which the assembly kits resided) to remove obsolete items.[43] The initial part of the Labor Study was devoted to just clearing SCE's planning system of obsolete assembly kits. In the latter phase, the teams updated the labor hours

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41 Specifically, the experts came from the Metro West, Metro East, North Cost, Desert and Orange areas of SCE's service territory.

42 Separately, approximately 3,900 CUs for substation and sub-transmission assets were reviewed and migrated into SAP.

43 For example, if the Material Management System referred to a transformer with certain voltage requirements that were no longer applicable, that assembly kit was removed.

of the most commonly used CUs—transformers, switches and poles. The goal was to approximate labor hours as precisely as possible in order to improve crew scheduling times and cost estimates.[44] The team based labor hour estimates on the expert judgment and analysis of T&D employees, taking into consideration factors such as crew size, whether the work is performed energized, and whether the crews would have vehicle access. The work also involved examining individual CUs to assign updated removal and installation hours. The end result of the panel of experts' process was to review—and, if necessary, revise—the installation and removal hours (the removal hours assigned in the old assembly kits had been set at roughly half of installation hours). The updated labor values were developed using an average of the best, typical and worst case scenario specific to the installation and removal of a CU.

By 2010, the update process for the CUs had been completed, but SCE uses an ongoing governance structure to further update CUs on an ad hoc basis when required. There are three full-time employees whose job is focused on maintaining and updating CUs so that proposed/required changes flow through a standard process. The CU team receives an average of 22 requests each year to create new CUs (from planning, engineering, apparatus and meter services). The team also receives approximately 60 requests each year to review the accuracy of specific CUs (requesting review of hours or material components). Of the approximately one thousand field requests that have come through to examine CUs since 2010, less than a handful of requests actually resulted in changes to the installation/removal hours. This is due both to the comprehensiveness of the 2009-2010 Labor Study and the reality that work processes/practices do not change so significantly over time as to impact cost of removal ratios.

When planners use CUs to design and estimate particular jobs, they may—based on their own experience or through discussions with field personnel—supplement the labor estimates with additional Install, Removal or Expense labor hours on a work order-by-work-order basis. Any changes made to the project based on job complexity, additional crew tailboards, additional traffic control requirements, travel time, etc. are used for that specific work order only, and do not result in updating the master CU in the CU library. Updates to the CUs in the CU library occur occasionally. For example, in August 2012, a manager within the Street and Outdoor Lighting Organization requested that the CU team review the installation hours for street light photocells given his assessment that the 0.5

[44] Work under Rules 2, 15, 16 and 20 benefit from accurate cost estimates built into CUs because those estimates form the basis for how customers are billed.

man hours for installation of this CU appeared high. The CU team pulled together a team of subject matter experts to assess and recommend a revision to the hours and determined that it should be reduced to 0.1 hours. Upon approval, the update was made in DM.

(3) 2016 Comparison of Standard Rates Table and CUs

In 2016, SCE undertook a study comparing the Standard Rates Table allocations with what the allocations would be if SCE's fixed asset accounting process mapped the CU process described above. The scope of the study included a review of over 70,000 individually planned distribution orders developed in Design Manager in 2015, which collectively amounted to $1.7 billion, or approximately 84% of that year's capital expenditures. The review included comparing the installation and removal cost allocation from DM against the Standard Rates Table allocation for all 70,000 orders. The results indicate that the planners' CU-based approach, which is more detailed than the higher-level aggregation of the CPR-based allocations in the Standard Rates Table, results in cost assignments substantially similar to the Standard Rates Table (validated by the 2004 and 2006 Study results based on the panels of T&D experts).[45]

D. SCE's Experience with Increasingly Negative Net Salvage Rates

NSRs are typically negative because gross salvage is largely negligible compared to the cost of removal. The main reason for more negative NSRs can be attributed to the results of this mathematical formula: (1) costs to retire assets (numerator) in today's dollars divided by (2) the age and original cost of assets retired (denominator). Since 2002, SCE's 5-year rolling average NSR has more than tripled for distribution infrastructure, from -66% to -283% as shown in Figure II-7 below.

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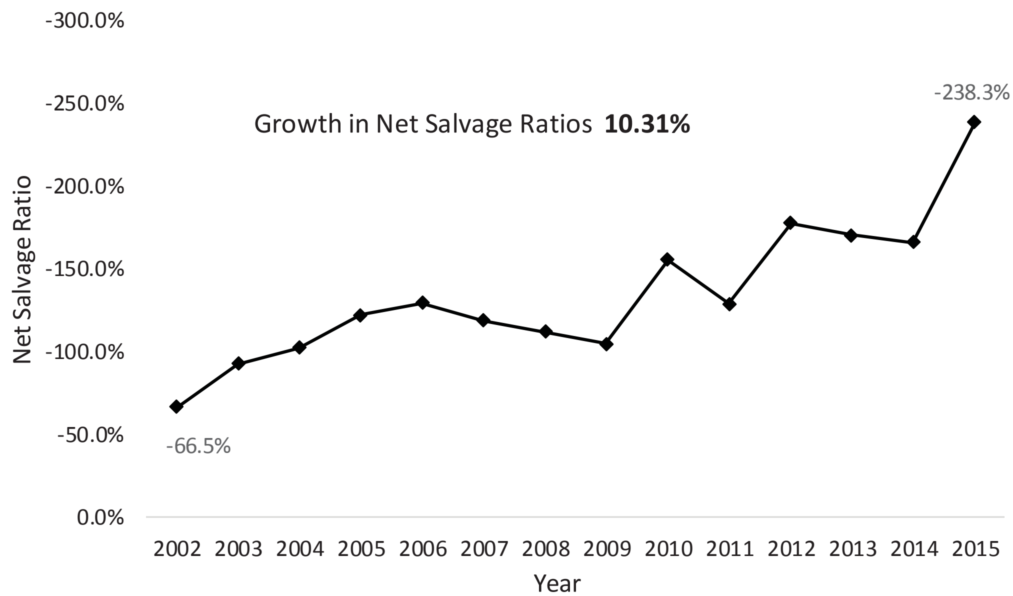
[45] Refer to WP SCE-09 Vol. 03, Book A, pp. 189-197 (2016 Study Results).

Figure II-7
Realized Net Salvage Ratios
Distribution Plant 2002-2015



For the last twenty years, SCE has experienced increasingly negative net salvage ratios for reasons explained in the next sections.

1. <u>The Average Age of Retirements is Increasing</u>

a) <u>Age and Inflation Impacts on Recorded Net Salvage Ratios</u>

An important consideration for the net salvage ratio calculation is that the numerator (net salvage cost) and the denominator (original cost) are stated in dollars spent at different points in time. The original cost retired in the denominator are measured in dollars from the time the plant was first placed in service (*i.e.*, older dollars) and the net salvage amounts in the numerator are measured when the plant is retired from service (*i.e.*, using more recent dollars). For example, a distribution pole placed into service in 1970 and retired in 2015 will have an original cost stated in 1970 dollars, but the removal costs will be incurred using 2015 dollars. Consequently, the temporal distance between installation and removal can have a significant effect on net salvage ratios primarily due to the effects of inflation. The effects of inflation are most apparent in the removal cost ratio, as the cost to retire (*i.e*., labor) is what is subject to the forces of inflation.[46]

[46] Refer to WP SCE-09 Vol. 03, Book A, pp. 198-201 (Experienced Net Salvage Rates) - *Depreciation Systems*, Frank K. Wolf and W. Chester Fitch, Iowa State University Press, pp. 53-55.

To illustrate the impact of inflation using a real life example, Table II-12, below, shows that the removal cost ratio increases with the age of the pole retired. Column C reflects the original cost of the pole being retired, while column D represents the removal cost in current dollars.

Table II-12
Plant Retirement and Removal Cost
(As Experienced for Distribution Poles – Account 364)
Data based on averages from 2009 to 2015

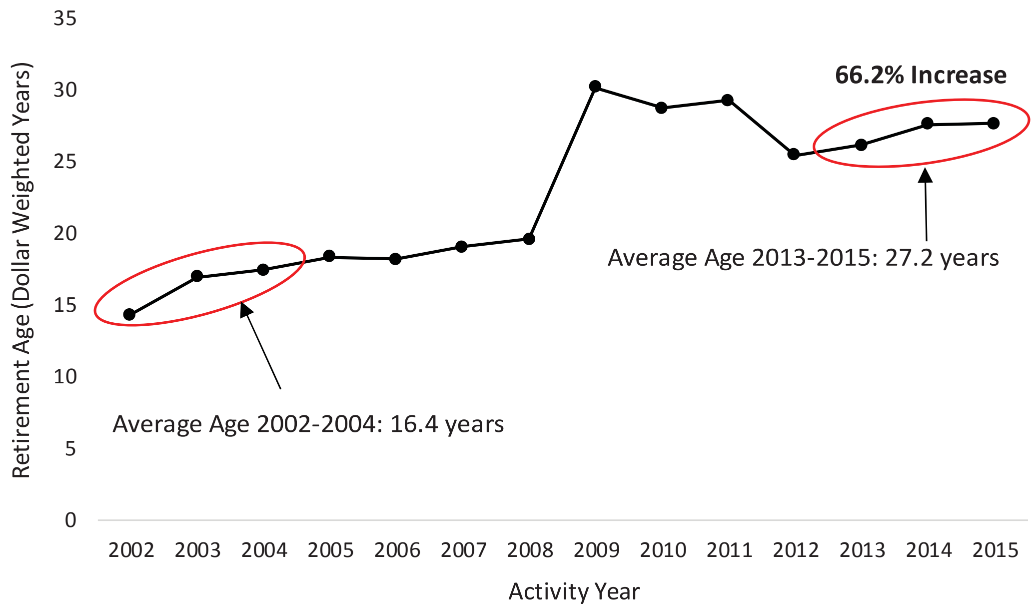
Vintage	Age of Pole Retired	Original Cost of Pole Retired	Per Pole Removal Cost	Removal Cost Ratio
A	B	C	D	E=D/C
2010	2.5	$7,599	$2,862	38%
2000	12.5	$3,547	$2,862	81%
1990	22.5	$1,413	$2,862	203%
1980	32.5	$622	$2,862	460%
1970	42.5	$369	$2,862	775%
1960	52.5	$167	$2,862	1717%

The table above demonstrates that as the age of the asset retired grows, the effects of inflation have an increasingly large impact on the realized removal cost ratio. This occurs because the average cost to install a pole in 1960 (Column C) would be significantly lower than the average cost to install a pole today, while the cost to remove each pole (Column D) is the same regardless of the age of the pole retired.

b) <u>SCE's Aging Retirements</u>

For multiple GRCs, T&D experts have testified about the advancing age of SCE's infrastructure. As the system matures, the average age of any retirement can be expected to be older than what was experienced in the past. As the system ages, the incidence of age related failures will increase. In fact, as shown in Figure II-8, below, this has been SCE's experience with distribution infrastructure for the past 13-years.

Figure II-8
Average Age Of Distribution Infrastructure Retired



As the age of T&D retirements increases, the original cost of the retirements has remained low, resulting in an increase in the experienced net salvage ratios.

2. Total Cost Increases Affect Cost of Removal

Over the last several rate cases, T&D experts have testified to the increasing need for capital to replace aging T&D infrastructure. This capital (including both the cost to remove and install) has been discussed by multiple witnesses over more than a decade of rate cases. In each case, witnesses have testified to cost pressures from the effects of: increasingly urban environments, increasing labor and contractor rates, increased permitting costs, more stringent environmental regulations, disposal fees, and system complexity.

For example, in the 2006 GRC the T&D Infrastructure Replacement witness provided the following still-relevant discussion on why the cost to retire assets in urban environments is higher than in rural areas:[47]

1) Permitting: Pole contractors are almost always required to obtain a city permit before initiating the work. In rural areas, permits are almost never required.

[47] 2006 GRC SCE-03 Vol 03 Part III pp. 14-15 and 2009 GRC SCE-03 Vol 03 Part III pp. 20-21.

2) Accessibility: Urban areas are frequently inaccessible by trucks and require that a crane be rented or that the pole be carried into the back yard and set manually. Rural areas are typically truck-accessible.

3) Congestion: Higher customers per circuit in urban areas contribute to higher congestion per pole than in rural areas. For example, an urban pole can be expected to be taller, as well as have more conductors, transformers, and cross-arms than a rural pole. In addition, the work may be performed on energized lines requiring specially trained crews and safety requirements.

4) Repairs: Urban areas frequently require that repairs are made to the concrete sidewalks, a requirement not typically necessary in rural areas.

Los Angeles County's population experienced significant growth[48] in the post-World War II period through the 1970s. This post-war population growth has increased the level of urbanization across SCE's service territory, putting upward pressure on costs. As a result of this, when assets originally installed in a rural environment are removed, the net salvage ratio reflects a very low original install cost for these assets. But these same assets are likely being replaced in a now more urban environment, adding to the upward pressure on removal cost. This experience can have a significant effect on the net salvage ratios—lower original cost (denominator) and higher cost of removal (numerator).

Given the increasing age of this infrastructure and the increasing urbanization associated with the post-war population growth, increases in the realized net salvage ratios is not surprising. As a result, however, the conditions present in SCE's service territory over this period of time may not be a realistic expectation of the future. In this case, and as further discussed immediately below, a per-unit analysis controls for this variation, and better represents SCE's expectation about the future levels of net salvage.

3. SCE's Per-Unit Analysis is Indifferent to the Realized Net Salvage Ratios

As described in Section B.1 of Chapter II, a per-unit analysis takes a different approach than Standard Practice U-4 in analyzing the expected levels of future net salvage. Rather than reviewing the relationship between historical costs of assets and the net salvage experienced in the past, the per-unit analysis uses the recorded average cost to retire each unit of property, and then applies per-unit

[48] 2009 GRC SCE-03 Vol 03 Part 3 p. 15 (SCE Territory – Population and System Demand).

costs to existing plant balances to forecast future net salvage given the anticipated timing of retirements. This approach to estimating future net salvage helps ensure that the results of the analysis are applicable to the mixture of plant that is serving customers today. Over time, as this mix of plant balances change, SCE will have the opportunity to reflect these changes in future per-unit analyses presented in its rate cases.

III.

DEPRECIATION STUDY

Chapter II, above, explained how SCE complied with the Commission's compliance directives and addressed the difference between traditional and per-unit analyses. The depreciation study addressing T&D assets, presented in Section A in Q&A format, was undertaken by an external consultant, Ronald E. White Ph.D. of Foster Associates Consultants, LLC. Dr. White provided SCE with life and net salvage parameters that SCE then used to calculate the proposed depreciation rates. SCE also conducted an in-house depreciation study of its Generation and G&I depreciable plant assets, discussed by an in-house SCE expert witness in Section B, below.

Unlike the Simulated Plant Record (SPR) procedure used in prior SCE rate cases, Dr. White performed an *actuarial* service life analysis using aged data from 2002 to 2015. In the 2012 GRC, the Commission stated that aged data is likely to be more reliable than SPR data, and it ordered SCE to "inform the Commission whether it used any aged data, and if not, when sufficient data is expected to be available."[49] In its 2015 GRC testimony, SCE stated that it began collecting aged data in 2008 and that it did not have sufficient aged data to perform an effective actuarial life analysis for the 2015 GRC.[50] This statement was based on an incorrect assumption that the Company began collecting aged data in 2008 when it implemented PowerPlan as its capital system of record.[51] In preparing its showing for this proceeding, SCE discovered that PowerPlan contains reconciled aged plant activity from 2002 forward. Thus, for this GRC, Foster Associates LLC performed an actuarial life analysis using the aged data from 2002 to 2015.[52]

Section A of Chapter III, below, which is in Q&A format, is the direct testimony of Dr. Ronald E. White of Foster Associates LLC.

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[49] D.12-11-051 p. 685.

[50] *See* Testimony in 2015 GRC, SCE-10, Vol. 02, Revision 1A, p. 33. SCE stated that it expected that aged data may become useful "in 10 years or so." *Id*.

[51] PowerPlan was used only as the depreciation system of record prior to 2008.

[52] SCE possesses some aged retirement data from 1994 through 2001 in Excel format outside of SCE's current capital system of record (PowerPlan). Neither SCE nor its outside expert evaluated or relied on the aged data in the 1994-2001 Excel sheets.

A. T&D - Average Service Life and Net Salvage Proposals

1. Development of Depreciation Rates

Q. PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval.[53] A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the

[53] The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. PLEASE DESCRIBE THE PRINCIPAL STEPS INVOLVED IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the Company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

Average and future net salvage rates are ideally estimated from a historical analysis of the cost per unit to install and the net cost per unit to retire major retirement units. A per unit analysis explicitly recognizes that the cost per unit to retire an asset is independent of the age of the asset when it is retired from service. The cost to retire a foot of conductor today, for example, is no different for a conductor that was installed yesterday or a conductor that was installed many years ago. As a result, percentage rate required to accrue for $5 per foot of removal expense on a conductor costing $10 per foot to install is twice the rate required to accrue the same amount of removal expense on a conductor costing $20 per foot to install.

Although a per unit analysis of installation and retirement costs is the most desirable treatment of net salvage, time and cost considerations (as well as the availability of the required data) often dictate a less rigorous analysis. Net salvage rates are frequently developed from a historical analysis using a three to ten–year moving average of the ratio of realized salvage and cost of removal to associated retirements. Net salvage estimates are also obtained from engineering studies of the cost to dismantle or abandon existing facilities.

2. <u>2016 Service–Life Study</u>

Q. DID SCE PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR ESTIMATING SERVICE LIFE PARAMETERS?

A. Yes. Service life statistics estimated in the 2016 study were derived from plant accounting transactions recorded over the period 2002 through 2015. Detailed accounting transactions were extracted from the Continuing Property Record (CPR) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The accuracy and completeness of the assembled database was verified for activity years 2002 through 2015 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Age distributions of surviving plant at December 31, 2015 were reconciled to the CPR.

Q. HOW WERE SERVICE–LIFE ESTIMATES DERIVED FOR SCE PLANT AND EQUIPMENT?

A. As noted above, the first step in estimating service lives is called *life analysis*. All transmission, distribution and general depreciable plant accounts were analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function was expressed as a survivorship function, which was numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category. The analysis of each plant account is contained in Appendix A.

Q. PLEASE EXPLAIN IN GREATER DETAIL HOW LIFE ANALYSES WERE CONDUCTED IN THE 2016 STUDY.

A. The fundamental probability distribution of interest in estimating the service life of industrial property is called a *hazard function*. This function, which is also used in reliability theory, is an equation that describes the conditional probability of retirement (called a *hazard rate*) during an age interval given survival to the beginning of the interval. So, for example, the probability that plant that has been in service, say for 5 years, will be retired during the 6th year is a conditional probability of retirement. In other words, the probability is conditioned upon having achieved an age of 5 years.

Graduating or smoothing observed hazard rates is an application of inferential statistics which draws inferences and predictions about a population based on samples of data taken from the population of interest. Projection lives and projection curves are population parameters "inferred" from a statistical analysis of the underlying forces of retirement described by probability distributions.

The object of a statistical analysis of plant retirements is to find the form of an equation that best describes the conditional probabilities of retirement, where the form of the equation is driven by the underlying forces of retirement. Any number of equations can be considered as candidates for selection. The so–called Iowa curves are a family of distributions most often used in conducting depreciation studies.

Each Iowa curve has a unique hazard function derived from the ratio of its retirement frequency distribution to its survivor distribution. Unfortunately, however, Iowa hazard functions cannot be written as explicit equations. It is for this reason that polynomials of the form $y = a + bx + cx^2 + dx^3$ are used to estimate hazard functions. The variable y is the hazard rate and *x* is the age interval of the rate.[54] A polynomial can be transformed into a survivor function and plotted against an Iowa curve to visually observe the derived survivor curve expressed as an Iowa curve.

The problem, therefore, is to estimate the coefficients (*i.e*., *a*, *b, c* and *d*) of the polynomial from an estimate of hazard rates derived from a sampling of historical retirements recorded for a plant category. Different estimators of the hazard rate can be used depending upon the desired statistical properties of the estimator. The ratio of retirements to exposures is most often used for depreciation studies.

Coefficients were estimated in the 2016 study using *Orthogonal Polynomials.* An orthogonal polynomial is not a special form of a polynomial. It is a procedure developed by Tchebysheff to estimate the coefficients of a polynomial (using regression) without rewriting the normal equations for each successive power of the polynomial. The coefficients of a second degree equation, for example, can be derived from a first degree equation without rewriting the equations used in a normal least squares regression.

Coefficients and polynomials were estimated for numerous trials or samples of retirements recorded over various bands of activity years. An activity year is the calendar year in which retirements were recorded. Retirements from vintages of like ages are combined to increase the size of the samples from which hazard rates are estimated. The motivation for examining various bands of activity years is to observe service–life trends to the extent they may be detectable.

Each polynomial was transformed or converted to a survivor function (or survivor curve when plotted) from which an estimate of the projection life was derived. The polynomial form of the hazard functions were also plotted and visually inspected as an aid to better understanding the forces of retirement acting upon a plant category.

Polynomials transformed to survivor functions were then fitted to Iowa–type curves with projection lives set equal to those derived from the polynomials. The purpose of fitting to Iowa curves is to obtain service–life descriptors more familiar to users of Iowa curves. It would be more obscure and less informative to describe survivor curves by the coefficients of a polynomial.

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[54] The reason polynomials are limited to a third degree term (*i.e*., a polynomial having an x^3 term) is that some low modal Iowa curves exhibit two inflection points in a plot of the hazard function.

Q. WERE FACTORS OTHER THAN SERVICE–LIFE INDICATIONS DERIVED FROM THE STATISTICAL STUDIES CONSIDERED IN ESTIMATING SERVICE–LIVES FOR SCE?

A. Yes. As discussed earlier, estimating service lives is a two–step procedure. The first step (life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of past forces of retirement acting upon a plant category and an estimate of the projection life implied from observed historical experience.

The second step (life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement and the service life of future plant additions. It is a process of blending the results of a life analysis with information (mostly qualitative) and informed judgment to obtain an appropriate projection life and curve descriptive of future expectations. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future. Both life analysis and life estimation require an understanding of the limitations of statistical studies and the need for reasonable and informed judgment.

Q. ARE FACTORS YOU CONSIDERED IN LIFE ESTIMATION DESCRIBED IN THE 2016 STUDY?

A. Yes. Appendix A contains a narrative explanation of both quantifiable factors (life analyses) and non–quantifiable factors (largely life estimation) considered by Foster Associates in recommending appropriate projection lives and curves for SCE. In those instances in which statistical indications could not be derived and/or observed indications were adjusted for operational, financial or ratemaking reasons, Foster Associates deferred to SCE in the selection of appropriate service lives.

Q. IS A PROJECTION LIFE THE SAME AS AN AVERAGE SERVICE LIFE?

A. No. A projection life is an estimate of the mean service–life of the population from which retirements are a random sample. The *average* service life of a plant category is a function of the age distribution of surviving plant (*i.e.*, plant currently in service by vintage–year of installation) and a selected level of asset grouping such as broad–group, vintage–group or equal-life group. If retirements are distributed over varying ages, the broad–group procedure (which assumes that each vintage has the same average service life) is the only grouping of assets that will produce an average service life equal to the projection life estimated for a plant category.

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR SERVICE–LIFE STUDY.

A. Current and recommended projection lives and dispersions are summarized in Table III-13 below.

Table III-13
Service Life Statistics

Account Description	Current		Recommended	
	P-Life	Dispersion	P-Life	Dispersion
A	C	D	E	F
Transmission Plant				
352.00 Structures and Improvements	55.00	S3	55.00	L1
353.00 Station Equipment	45.00	R0.5	40.00	L0.5
354.00 Towers and Fixtures	65.00	R5	65.00	R5
355.00 Poles and Fixtures	50.00	R0.5	65.00	SC
356.00 Overhead Conductors and Devices	61.00	R3	61.00	R3
357.00 Underground Conduit	55.00	R3	55.00	R3
358.00 Underground Conductors and Devices	40.00	R2.5	45.00	S1
359.00 Roads and Trails	60.00	SQ	60.00	R5
Distribution Plant				
361.00 Structures and Improvements	42.00	R2.5	50.00	L0.5
362.00 Station Equipment	45.00	R1.5	65.00	L0.5
364.00 Poles, Towers and Fixtures	47.00	L0.5	55.00	R1
365.00 Overhead Conductors and Devices	45.00	R0.5	55.00	R0.5
366.00 Underground Conduit	59.00	R3	59.00	R3
367.00 Underground Conductors and Devices	45.00	R0.5	43.00	R1.5
368.00 Line Transformers	33.00	R1	33.00	S1.5
369.00 Services	45.00	R1.5	45.00	R1.5
370.00 Meters	20.00	R3	20.00	R3
373.00 Street Lighting and Signal Systems	40.00	L0.5	48.00	L1
General Plant				
390.00 Structures and Improvements	38.00	R3	45.00	R0.5

Table 1. Service Life Statistics

3. <u>2016 Net Salvage Study</u>

Q. WHY IS NET SALVAGE RECOGNIZED IN THE COMPUTATION OF DEPRECIATION ACCRUAL RATES?

A. Depreciation is a measurement of the service potential of an asset that is consumed during an accounting interval. The cost of obtaining a bundle of service units (*i.e.,* a future net revenue stream) is represented by an initial capital expenditure which creates a revenue requirement for return and depreciation, and a future expenditure which creates a revenue requirement for cost of removal reduced by salvage proceeds. The matching principle of accounting provides that both the initial and future expenditures should be allocated to the accounting periods in which the service potential of an asset is consumed. The standard or criterion that should be used to determine a proper net salvage rate is, therefore, cost allocation over economic life in proportion to the consumption of service potential. If some other standard (such as cash flow or revenue requirements) is considered more important in setting depreciation rates, then cost allocation theory must be abandoned as the foundation for depreciation accounting.

The need to include net salvage in the development of depreciation rates is widely recognized and accepted by a substantial majority of state regulatory commissions as a standard ratemaking principle. The FERC Uniform System of Accounts (USoA), for example, describes depreciation as the "… loss in service value" where service value is defined as "… the difference between original cost and net salvage value of gas plant." Net salvage value means "the salvage value of property retired less the cost of removal."

The economic principle underlying both the accounting and ratemaking treatment of net salvage is that in addition to return *of* and return *on* invested capital and taxes, a revenue requirement for removal expense (or a reduction in the revenue requirement attributable to gross salvage) is created when an asset is placed in service. It is customary and appropriate for regulated utilities, therefore, to include a net salvage component in its depreciation rates to more nearly achieve the goals of depreciation accounting and to equitably distribute the revenue requirement for removal expense over the period in which the assets that created the requirement are used to provide utility service.

Q. WHAT IS A FUTURE NET SALVAGE RATE?

A. Future net salvage (in percent) is the sum of future net salvage (*i.e.*, gross salvage less cost of removal) at a given observation age divided by the surviving plant investment at that age.

Q. WHAT IS AN AVERAGE NET SALVAGE RATE?

A. Average net salvage (in percent) is the sum of realized and future net salvage divided by the plant investment at age zero. Stated differently, average net salvage is the total estimated salvage less cost of removal for a vintage (or group of vintages) expressed as a percent of the original vintage additions. Future net salvage is related to the surviving plant of a vintage (or group of vintages) whereas average net salvage is associated with the original vintage addition.

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S DECISION IN SCE'S 2015 GRC (D.15-11-021) REGARDING NET SALVAGE PROPOSALS?

A. Yes. In the 2015 GRC Decision, the Commission directed SCE to provide more detail in support of its net salvage proposals for at least five of the largest accounts, as measured by proposed annual depreciation expense. At a minimum, this detail shall include:

1. "A quantitative discussion of historical and anticipated future Cost of Removal (COR) on a per unit basis for the large (greater than 15% as measured by the portion of plant balance) asset classes in the account. This discussion should identify and explain the key factors in changing or maintaining the per–unit COR."
2. "A quantitative discussion of historical and anticipated future retirement mix (i.e., retirements among different asset classes), identifying and explaining the key factors in changing or maintaining this mix."
3. "A quantitative discussion of the life of assets and original cost of assets being retired, in relation to the COR, on both a historical and anticipated future basis. This discussion should be integrated with and/or cross–reference the proposal for life characteristics."
4. "An account–specific discussion of the process for allocating costs to COR."[55]

a) Directive No. 1

Q. WERE HISTORICAL AND FUTURE NET SALVAGE COSTS DERIVED ON A PER UNIT BASIS IN COMPLIANCE WITH THE COMMISSION'S FIRST DIRECTIVE?

A. Yes. Per unit net salvage analyses were conducted for the nine (9) plant accounts listed in Table III-14, below.

[55] D.15-11-021, pp. 554-555.

Table III-14
Per Unit Net Salvage Accounts

Account Description
354.00 Towers and Fixtures
355.00 Poles and Fixtures
356.00 Overhead Conductors and Devices
364.00 Poles, Towers and Fixtures
365.00 Overhead Conductors and Devices
366.00 Underground Conduit
367.00 Underground Conductors and Devices
368.00 Line Transformers
369.00 Services

Table 2. Per Unit Net Salvage Accounts

Each of the nine plant accounts was grouped into one or more subpopulations of major equipment categories. Historical per unit ratios (defined as net cost per unit to retire divided by the cost per unit to install) were used in both the historical and future per unit analyses. Net costs to retire (or net salvage) were used in the analysis to maintain consistency with future net salvage parameters used in the formulation of remaining–life accrual rates. Gross salvage is generally small in relation to cost of removal.

Historical per unit ratios were examined and compared with the ratio of realized net salvage to the associated retirements. In most instances, the ratio of net salvage to retirements is greater than historical per unit ratios observed over the period 2009–2014. This is predictable since net savage is recorded in current dollars and retirements are recorded in historical dollars.

Future per unit ratios were derived using a weighted average of the subpopulation net salvage per unit values recorded over the period 2009–2015. These values appear in the numerator of future per unit ratios. This treatment was decided after multiple meetings and discussions with SCE engineers and subject matter experts who reported that SCE has no planned or expected changes in retirement activities that would measurably change average net salvage per unit values recorded in recent activity years. Other than recognizing future inflation, historical net salvage per unit values were therefore retained in the forecast of future net salvage rates. Subpopulations and average historical per unit net salvage costs are summarized in Table III-15 below.

Table III-15
Average Net Salvage Per Unit to Retire

Account and Subpopulation	12/31/2015 Plant	12/31/2015 Percent	Avg. Add Per Unit*	Avg. NS Per Unit*
A	B	C	D	E
354.00 Towers and Fixtures				
A. Towers Soley Owned >= 230 kV	$ 1,139,621,027	91.8%	$610,475	$ 57,365
B. Towers < 230 kV, Common and Other	101,453,733	8.2%	321,711	6,628
	1,241,074,760	100.0%		
355.00 Poles and Fixtures				
A. Wood, Fiber Glass and Composite	375,781,560	47.2%	14,939	4,517
B Light Duty Steel	419,049,403	52.6%	18,775	10,281
C Retaining Walls	1,261,756	0.2%	145,988	(36,480)
	796,092,719	100.0%		
356.00 Overhead Conductors and Devices				
A. Conductor < 220 kV	202,769,129	18.7%	11	5
B Conductor >= 220 kV	739,015,019	68.3%	38	6
C Disconnect Switches	27,761,688	2.6%	42,650	11,921
D Ground Wire	113,151,541	10.5%	20	(46)
	1,082,697,377	100.0%		
364.00 Poles, Towers and Fixtures				
A Wood, Fiberglass and Steel Poles	2,191,572,261	100.0%	6,882	2,700
	2,191,572,261	100.0%		
365.00 Overhead Conductors and Devices				
A Overhead Conductor	946,696,334	68.6%	8	3
B Switches	347,104,388	25.1%	12,828	3,384
C Breakers, Reclosures and Other	87,013,183	6.3%	2,404	358
	1,380,813,905	100.0%		
366.00 Underground Conduit				
A Pull and Slab Boxes	447,741,061	13.0%	949	1,305
B Below Ground Conduit	789,932,796	22.9%	23	1
C Vaults	324,651,530	9.4%	7,584	23,101
D Excavation Trenches	16,836,983	0.5%	(77)	
E Manholes and Other	157,068,859	4.6%	1,258	462
	1,736,231,229	50.3%		
367.00 Underground Conductors and Devices				
A Underground Cable	4,452,641,073	84.6%	25	10
B Breakers, Switches, Reclosures	809,879,908	15.4%	8,567	4,896
	5,262,520,981	100.0%		
368.00 Line Transformers				
A Overhead Transformers	1,045,618,106	30.3%	2,655	561
B Underground Transformers	1,262,937,734	36.6%	5,899	1,459
C Lightening Arresters and Fuse Holders	749,306,101	21.7%	924	161
D Switches, Breakers, Capacitors, etc.	393,008,343	11.4%	5,658	960
	3,450,870,284	100.0%		
369.00 Services				
A Underground Conductor	783,834,596	61.2%	301	221
B Overhead Conductor	387,892,896	30.3%	236	123
C Risers	63,694,659	5.0%	881	450
D Underground Conduit and Other	44,872,497	3.5%	12	0
	1,280,294,648	100.0%		

*2009 - 2015

Table 3. Average Net Salvage Per Unit to Retire

The per unit cost of plant additions used in forecasting future net salvage rates was obtained by dividing vintaged plant in service at December 31, 2015 (*i.e.*, age distributions of surviving plant) by vintaged units in service within each subpopulation. The ratio of average net salvage per unit experienced over the period 2009–2015 (adjusted for inflation) to the per unit cost of plant in service is the ratio that was applied to forecasted retirements to estimate future net salvage for each vintage. The sum of future net salvage over all vintages divided by current plant account balances produces an estimated future net salvage rate for each primary account. The formulation of per–unit net salvage rates is contained in Appendix B.

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR PER UNIT NET SALVAGE ANALYSIS.

A. Future net salvage rates derived with inflation rates ranging between zero (0) and three (3) percent are summarized in below.

Table III-16
Future Net Salvage Rates

Account Description	Projection Curve	Inflation Rate 0%	1%	2%	2.72%
A	B	C	D	E	F
354.00 Towers and Fixtures	65-R5	104%	125%	155%	185%
355.00 Poles and Fixtures	65-SC	90%	155%	295%	499%
356.00 Overhead Conductors and Devices	61-R3	114%	141%	178%	210%
364.00 Poles, Towers and Fixtures	55-R1	180%	249%	361%	488%
365.00 Overhead Conductors and Devices	55-R0.5	195%	272%	397%	538%
366.00 Underground Conduit	59-R3	108%	170%	276%	401%
367.00 Underground Conductors and Devices	43-R1.5	112%	150%	205%	261%
368.00 Line Transformers	33-S1.5	27%	33%	40%	47%
369.00 Services	45-R1.5	178%	231%	309%	387%

Table 4. Future Net Salvage Rates

Q. HOW WERE NET SALVAGE RATES ESTIMATED FOR ACCOUNTS NOT INCLUDED IN THE PER UNIT NET SALVAGE ANALYSIS?

A. A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used to: a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future. The analysis of net salvage is contained in Appendix A.

Although future per unit ratios applied to a forecast of future retirements provides a more rigorous estimate of future net salvage rates, it is the opinion of Foster Associates that the ratio of realized net salvage to retirements provides reasonable estimates of future net salvage rates to the extent that future inflation is similar to the past. Estimating depreciation rates, however, is not an exact science; errors of estimate in both service lives and nets salvage rates will always remain.

b) Directive No. 2

Q. WERE HISTORICAL AND FUTURE RETIREMENT MIXES EVALUATED IN COMPLIANCE WITH THE COMMISSION'S SECOND DIRECTIVE?

A. Yes. As noted above, each of the nine plant accounts was divided into one or more subpopulations of major equipment categories. The mix of equipment classified in each subpopulation and the size of each subpopulation as a percent of the current investment in each related plant account were reviewed by SCE engineering and plant accounting personnel. No key factors were identified from this review that would suggest the future retirement mix or relative size of each subpopulation will be significantly different from the current composition and grouping of subpopulations.

c) Directive No. 3

Q. WERE RECOMMENDED LIFE CHARACTERISTICS AND NET COST OF REMOVAL INTEGRATED IN COMPLIANCE WITH THE COMMISSION'S THIRD DIRECTIVE?

A. Yes. The directive to provide a quantitative discussion of asset life and original cost of assets being retired, in relation to the COR on a historical basis, was interpreted to mean an examination of the average age of retirements associated with the recording of COR. Work papers supporting Appendix A provide a summary (Schedule E) of the average age of retirements and recorded COR for each of the per unit accounts. Although net salvage is often recorded subsequent to the recording of retirements, it can be observed that COR as a percent of retirements is a function of the age of retirements and generally increases with increases in the average age.

As noted earlier, a prospective per–unit analysis should be designed to produce estimates of future net salvage rates respecting the principle that the net cost per unit to retire an asset in independent of the age of the asset when it is retired from service. The percentage rate applied to the cost of an old asset to accrue the same cost per unit to retire a newer asset, however, depends upon the relative difference in the cost per unit incurred to install the assets. Integration of per unit ratios with life characteristics necessitates forecasting vintaged retirements using projection lives and curves estimated for each plant account.

Estimates of the amount and timing of future net salvage were derived from an application of the ratio of per unit net costs to retire and per unit installed costs of each vintage within a subpopulation, to future retirements (forecasted by vintage) using the projection lives and curves estimated in the statistical life studies. Inflation rates ranging between zero and three percent were employed in the analysis to recognize the likelihood of increasing net salvage solely attributable to inflation.

Other than a range of assumed inflation rates and parameters estimated in the service–life studies, no elements of qualitative judgment were required or exercised in estimating future net salvage rates from the per unit analysis.

d) Directive No. 4

Q. THE COMMISSION'S FOURTH DIRECTIVE IN APPLICATION A.13–11–003 WAS TO PROVIDE AN ACCOUNT–SPECIFIC DISCUSSION OF THE PROCESS FOR ALLOCATING COSTS TO COR. HAS SCE COMPLIED WITH THIS DIRECTIVE?

A. Yes. The process for allocating costs is described in the direct testimony of SCE witness Alan Varvis in this Exhibit.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

B. Generation and G&I - Average Service Life and Net Salvage Proposals

1. Purpose and Scope

This chapter covers the average service lives and net salvage proposals for SCE's Generation and General & Intangible (G&I) assets. For G&I assets, SCE proposes to retain the same service lives and net salvage rates as authorized in the 2015 GRC Decision.

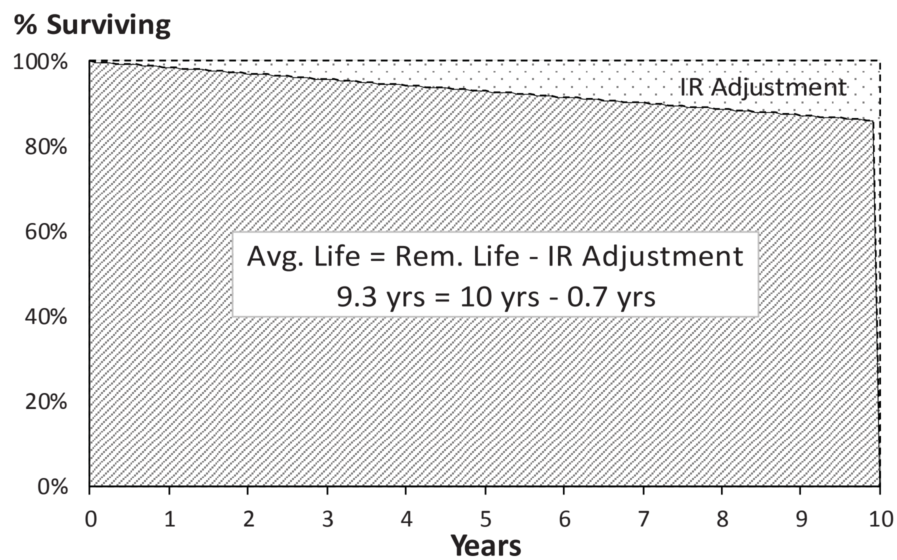
2. Generation-Related Property

a) Average Service Lives for Generation Assets

Generating facilities are life span assets that consist of large plant assets expected to retire all at one time, with some smaller components retiring earlier during the service life of the plant (called "interim retirements"). To determine the *average* life of the plant asset, SCE adjusts the life span downward to take into account the shorter-lived interim retirements. The life span for a generating facility as a whole depends on the factors affecting the final shutdown: operating license, fuel and resource availability, contractual obligations, the relative efficiency of the generating units, and so forth. The total life span is determined largely as an engineering judgment based on the factors previously mentioned.

Interim retirements consist of such items as pumps, motors, and other individual generating components that retire depending on the factors specifically affecting them—wear and tear, reliability, obsolescence, and so forth. The impacts of the life span and the interim retirements on the overall average service life of the plant asset are determined separately. SCE considered the interim retirement adjustment first by estimating the future level of annual interim retirements as a percent of the plant balance (*i.e.*, an interim retirement rate or IR rate). The estimate of an IR rate is made by analyzing the historical levels of interim retirements. The determined annual IR rate is applied to the current plant balance over the remaining life of the plant to determine the necessary adjustment to the overall remaining life of the generating station. For example, if a generating plant has a 10-year remaining life and an IR rate of 1.4 percent per year, then about 14 percent of the current plant balance would retire as interim retirements (10 years times 1.4 percent year) and the remaining 86 percent would retire as a final retirement. The resulting survivor curve is shown in Figure III-9.

Figure III-9
Life Span Survivor Curve*



** Remaining Life Span = 10 years; IR Rate = 1.4%.*

As Figure III-10 demonstrates, the average life is equal to the life span adjusted for the shorter life of the interim retirements. The remaining life adjustment is calculated as follows:

Figure III-10
Life Span: Remaining Life Adjustment

$$\text{Remaining Life Adjustment} = \frac{\text{Rem. Life Span x IR Rate}}{2} \text{ x } \text{Rem. Life Span}$$

$$\text{0.7 Years} = \frac{\text{10 Years x 1.4\%}}{2} \text{ x } \text{10 Years}$$

Table III-17 summarizes SCE’s proposed generation average service lives as compared to those authorized in the 2015 GRC. What follows is a plant-by-plant discussion of the proposed average service lives.

Table III-17
Generation Service Life Spans

Generation Facility	Life Spans	
	Authorized	Proposed
A	B	C
Nuclear Production - Palo Verde	30.5 yrs	28.0 yrs
Hydro Production	26 yrs	19.9 yrs
Other Production		
Pebbly Beach	45 yrs	25 yrs
Mountainview	35 yrs	35 yrs
Peakers	35 yrs	35 yrs
Solar Photovoltaic	25 yrs	20 yrs
Fuel Cells	10 yrs	10 yrs
Energy Storage	N/A	10 yrs

(1) Palo Verde Nuclear Generating Station (PVNGS)

The Nuclear Regulatory Committee (NRC) licenses for PVNGS Units 1, 2, and 3 end June 1, 2045, April 24, 2046, and November 25, 2047, respectively, resulting in an average 30.5 year remaining life span for the station as of December 31, 2015. In addition, recent retirement activity supports adjusting the average remaining life down by 2.5 years to 28 years to account for the effect of interim retirements.

(2) Hydro Generation

SCE's hydro generation system consists of 76 generating units and associated facilities accounted for in 60 different accounting locations. Nearly all of SCE's hydro facilities (99 percent) is covered by FERC licenses. The licenses have a variety of termination dates—from expired (either in the process of being relicensed or decommissioned) to 2046. The total life span of SCE's current license periods for those plants without expired licenses range between 5 and 30 years. Recently, FERC has issued renewals with license periods averaging 40 years.

Prior license renewal does not guarantee that the generating plant will last indefinitely. There are no guarantees that the FERC will continue to grant the company licenses or that the generating units will continue to be economic. Moreover, the individual components making up a generating station will continue to wear out, be retired, and need to be replaced. Consequently, SCE proposes that the hydro generation plant be depreciated over the remaining life spans associated with the individual FERC licenses.[56] For generating stations with already expired, or within five years of license termination, SCE proposes that the life spans be extended by the estimated license life in its current FERC license applications.[57]

(3) Pebbly Beach

The Pebbly Beach generating station consists of six diesel generating units, ranging in capacity from 1.0 MW to 2.8 MW. In its last GRC, SCE was authorized a 45-year average service life for this account on the basis that each of the six units would experience increasing risk of obsolescence and failure after two overhaul cycles (approximately 22 years between overhauls). Because of the difficulty in sourcing alternative supply of generation for Catalina Island, SCE engineers expect these units to remain in-service for the foreseeable future. However, to help ensure continued operations, SCE engineers state that the units require a zero-time overhaul[58] after approximately 100 to 120 thousand operating hours. Based on SCE's actual experience with the operations of these units, the time between overhauls is approximately 25 years.

For example, the SCE is proposing to reduce the average service life for this account from the currently authorized 45 years to 25 years. This change is concurrent with moving the start of the amortization period from the vintage year to the date of the last overhaul. This 25-year life allows SCE to recover the cost of each zero-time overhaul over its useful life with little impact to the remaining life as shown in Table III-18 below.

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[56] In the case of the 1 percent of hydro plant not covered by a FERC license, SCE applies the average life determined for the plant that is covered by FERC license.

[57] The average application license period is 44 years. The exception to this life span extension is the amortization period for the hydro relicensing costs. These relicensing costs are only amortized over the associated license period for which they were spent.

[58] A zero-time overhaul restores operations of the unit to like-new operating conditions.

Table III-18 [59]
Comparison of SCE's 2015 Authorized and 2018 Proposed Lives for Pebbly Beach Generating Station

Line No.	Item	2015 GRC Authorized	2018 GRC Proposed
1.	Average Start Date	1986	2006
2.	Proposed ASL	45	25
3. = 1.+2.	Estimated Ret. Date	2031	2031
4. = 3. - 2015	Rem. Life a/o 1/1/2016	15.7	15.5

There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 15.5 years for this account.

(4) Mountainview

SCE is proposing to retain Mountainview's currently authorized 35-year life span as established in the 2015 GRC Decision. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 25 years for this account.

(5) Peakers

SCE is proposing to retain the currently authorized 35-year average service life for Peaker. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 28 years for this account.

(6) Solar Photovoltaic

The currently authorized average service life for Solar Photovoltaic (PV) equipment is 25 years. SCE is proposing to return to the previously authorized 20-year average service life. Based on discussions with SCE engineers[60] the major components of this account will have significantly shorter service lives than the currently authorized 25-year life. Engineers indicate that the

[59] Refer to WP SCE-09 Vol. 03, Book A, p. 203 (Generation Life Spans).
[60] Refer to WP SCE-09 Vol. 03, Book A, p. 204 (Generation Life Spans).

equipment in this account is expected to fail significantly sooner than the currently authorized 25-year authorized life. For example, the three main components[61] include:

- Solar Panels – 10-12 years
- Inverters – 5-8 years (warrantied for 5 years)
- Control System – 6-8 years for obsolescence to set in.

In addition, the rooftop leases granting SCE the rights to use the rooftop facilities is currently 20-years. Given the uncertainty of lease renewal and short expectations about the life of the equipment, a 20-year life proposal is reasonable for this account. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 16 years for this account.

(7) Fuel Cells

SCE owns and operates two fuel cell demonstration facilities. The plants, located at California State University, San Bernardino (CSUSB) and University of California Santa Barbara (UCSB) were installed in September 2012 and October 2013 respectively. SCE is proposing to retain the currently authorized 10-year average service life. This proposal is consistent with our expectations that title to the demonstration facilities will be transferred to the site owners at the end of their 10-year lease.

(8) Energy Storage

The Commission has required SCE to procure and install 580 MW of energy storage facilities in its service territory by 2020. These facilities represent emerging technology and face significant risk of technological obsolescence in the future. SCE estimates the life of Energy Storage by the design life, cycle times of the proposed facilities, discussion with engineers, reviewing of reputable engineering studies and benchmarking with industry peers. SCE proposes a 10-year average service life for the Energy Storage and this represents a reasonable estimate of the expected life of these facilities when they are deployed.

b) Net Salvage Rates for Generation Assets

As discussed above, generation properties are retirement units that will retire in full at a specific time. Although there are interim additions and retirements that occur over the service life of the plant, the plant as a whole is subject to final retirement. SCE's generating plants—Palo Verde,

[61] *Id*.

Hydro, Pebbly Beach, Mountainview, Peakers, Solar Photovoltaic, Fuel Cell—fit these characteristics. The net salvage for SCE's generation plants is considered using two basic elements—interim retirement net salvage and final retirement net salvage (*i.e.*, "decommissioning")—which are estimated separately. The final retirement net salvage entails an engineering estimate of the cost to remove and dispose of the plant and equipment existing at the time of the station's final shutdown.

In contrast to final retirements, interim retirement net salvage is the removal cost associated with the numerous small retirements occurring over the life of the generating station. This net salvage is estimated based upon an analysis of recorded interim net salvage ratios similar to the approach followed for mass property. Finally, the interim and final net salvage amounts are combined based upon the associated plant dollars to determine a total weighted average net salvage for the generating station. The estimated decommissioning costs at retirement are shown in the Table III-19 below. Interim retirement net salvage is relatively small with only a minor impact to amortization levels.

Table III-19
Generation Removal Cost

Plant	Decommissioning		Interim Retirement NS	
	Auth.	Prop.	Auth.	Prop.
A	B	C	D	E
Nuclear Production - Palo Verde	Covered Under NDCTP		-	$2.1 M
Hydro Production	-	-	$1.9 M	$4.5 M
Other Production				
Pebbly Beach	$6.6 M	-	-	-
Mountainview	$16.3 M	$16.2 M	-	-
Peakers	$12.1 M	$14.9 M	-	-
Solar Photovoltaic	$81.9 M	$80.8 M	-	-
Fuel Cells	-	-	-	-
Energy Storage	N/A	-	-	-

The net salvage estimates for generating stations will differ significantly depending upon a variety of factors. Although the net salvage consists of both interim retirement net salvage and final decommissioning costs, the scale of the decommissioning costs will generally drive the overall net salvage levels requested. In the case of Palo Verde, only interim retirement net salvage is included in the filing and is estimated to be zero percent at this time. The Commission will address the final decommissioning costs of Palo Verde in the Nuclear Decommissioning Cost Triennial Proceedings. The following sections discuss the decommissioning estimates for the respective generation facilities.

(1) Palo Verde Net Salvage

As previously mentioned, only interim retirements are addressed in this filing. While SCE did not request for interim retirement net salvage cost in its prior rate cases, recent retirement activity supports a modest increase. As such, SCE is proposing to include the interim retirement net salvage rates as shown in Table III-20, below.

Table III-20[62]
Palo Verde Interim Retirement Net Salvage

	Net Salvage Ratio (% of IRs)	Net Salvage Ratio (% of Plant)
Land and Land Rights	0.0%	0.0%
Structures and Improvements	-0.15%	0.0%
Reactor Plant Equipment	-20.0%	-3.7%
Turbogenerator Units	-16.0%	-5.9%
Accessory Electric Equipment	-13.0%	-0.6%
Misc. Power Plant Equipment	-16.0%	-2.0%

(2) Hydro Net Salvage

With the exception of San Gorgonio Unit 2, which is an active state of decommissioning, SCE is not requesting net salvage for decommissioning at this time. SCE is continuing to remove/retire San Gorgonio Unit 2 and is requesting $6.4M for the capital expenditures expected to be incurred from 2016 to 2019.

Interim retirement net salvage ratios for interim retirements are calculated by analyzing the recent retirement history for the level of net salvage incurred during interim retirements. The ratio of net salvage (gross salvage less cost of removal) divided by the retirement values is used to arrive at the net salvage ratios shown in Table III-21, below.

[62] Refer to WP SCE-09 Vol. 03, Book A, pp. 205-214 (Palo Verde Interim Retirements).

Table III-21[63]
Hydro Interim Retirement Net Salvage

	Net Salvage Ratio (% of IRs)	Net Salvage Ratio (% of Plant)
Structures and Improvements	-150%	-10.9%
Reservoirs, Dams and Waterways	-250%	-5.6%
Water Wheels, Turbines & Generators	-50%	-9.5%
Accessory Electric Equipment	-150%	-10.6%
Misc. Power Plant Equipment	-20%	-1.9%
Roads, Railroads & Bridges	-100%	-11.5%

(3) Pebbly Beach Net Salvage

Due to the expectations that the diesel generators will continue to operate in the foreseeable future, SCE is not proposing to recover any decommissioning costs in this rate case. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

(4) Mountainview Net Salvage

SCE compiled a list of equipment and facilities to be installed as part of the new generation facilities and itemized them by FERC plant account.[64] SCE then developed demolition costs for each component. The estimated decommissioning costs for Mountainview is $8.9 million (2012 dollars). SCE escalated the $8.9 million out to the end of the remaining life of the station, resulting in $16.2[65] million. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

(5) Peakers Net Salvage

In 2007, SCE commissioned Arcadis to perform decommissioning cost studies for each of its five Peaker units. Table III-22 below shows the current cost for each unit, totaling $7.7M. Escalated to the estimated year of final retirement produces a total future decommissioning cost of $14.9M.[66] Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

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[63] Refer to WP SCE-09 Vol. 03, Book A, pp. 215-223 (Hydro Interim Retirements).
[64] Refer to WP SCE-09 Vol. 03, Book A, pp. 308-313 (Mountainview Decomm).
[65] *Id.*
[66] Refer to WP SCE-09 Vol. 03, Book A, pp. 225-291 (Peakers Decomm).

Table III-22
Peaker Decommissioning Costs ($000's)

Line No.	Peaker Unit	2015 ($) Decomm	Retirement Year	Retirement Year Decomm ($)
1.	Barre	$1,427	2042	$2,676
2.	Center	$1,414	2042	$2,652
3.	Grapeland	$1,593	2042	$2,987
4.	McGrath	$1,683	2042	$3,155
5.	MiraLoma	$1,604	2047	$3,407
		$7,722		$14,877

(6) Solar Photovoltaic Net Salvage

In 2011, SCE commissioned Worley Parsons to conduct a decommissioning study of its Solar Photovoltaic Equipment. The study resulted in a range of estimates between $300,000 and $547,000 per megawatt in 2011 dollars based on the type of facility installed. Lower cost estimates are associated with ground mount installations characterized by ease of access and fewer equipment requirements, while the higher cost facilities are rooftop mounted that increase the complexity of removal activities. Escalating the estimates to the end of the proposed 20-year average service life results in a total decommissioning estimate of $81 million as shown in Table III-23. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

Table III-23
Solar Decommissioning Costs by Panel Type ($000's)

Installation Type	2015 $ Megawatt	Installed MW	Total Decomm 2015 ($)	Total Decomm Retirement Year ($)
A	B	C	D=B*C	E
Rooftop - Floating	$614	54	$32,890	$47,959
Rooftop - Anchored	$645	31	$20,071	$29,486
Ground Mount	$354	7	$2,395	$3,410
			$55,355	$80,855

(7) Fuel Cell Net Salvage

SCE is not proposing to recover decommissioning costs for Fuel Cells at this time because of the expectation to transfer ownership to site hosts at the end of their 10-year life.

While SCE is not proposing decommissioning at this time, it is not unreasonable to expect that if circumstances change, there will be future costs to retire these plants.

(8) Energy Storage Net Salvage

SCE is proposing to install lithium-ion battery units in a rack configuration. Engineers indicate that the removal activities to retire these assets include driving to the facility, removing the battery modules the rack, and shipping to recycling centers for disposal. Engineers also indicate that there may be a small amount of gross salvage associated with the recycling of the units. Although it is not unreasonable to assume that there may be increasing costs to retire these assets in the future (*e.g.*, if recycling salvage becomes disposal fees) SCE is not proposing decommissioning costs for energy storage assets at this time.

3. Forecast Service Lives for G&I Assets

Some categories of plant do not lend themselves to statistical analysis, but do not belong in the life span category. These plant assets include most general plant (*i.e.*, FERC Accounts 391-397), intangible plant (*e.g.,* software, radio frequencies, etc.), and easements. SCE determined average service lives through conducting discussions with SCE engineers familiar with the assets, considering prior company procedure, and being familiar with industry practice.

Table III-24, below, shows the forecast depreciation service lives for general and intangible plant accounts. The table compares SCE's proposed depreciation rates to authorized service lives from D.15-11-021 (the 2015 GRC Decision). As discussed in the sections below, because Power Management Systems (Account 391.4) and Telecommunications Equipment (Account 397) consist of sub-accounts of fairly disparate service lives, the subaccounts have been categorized based upon the equipment lives. For example, in the case of Telecommunication Equipment, SCE grouped Telephone Systems with Videoconferencing Equipment in a 7-year category separate from the infrastructure equipment such as open wire communication conductor and antenna support structures that belong in a 40-year category.

Table III-24[67]
General and Intangible Plant Service Life Proposals

Account No.	Account Description	2015-2017 Authorized (Years)	2018-2020 Proposed (Years)
General Plant			
391.1	Office Furniture	20	20
391.2	Personal Computers	5	5
391.3	Mainframe Computers	5	5
391.4	DDSMS-Power Management System	7.8	10.2
391.5	Office Equipment	5	5
391.6	Duplicating Equipment	5	5
391.7	PC Software	5	5
393	Stores Equipment	20	20
394	Tools & Work Equipment	10	10
395	Laboratory Equipment	15	15
397	Telecommunication Equipment	10.3	8.6
398	Misc Power Plant Equipment	20	20
Intangibles			
302.020	Hydro Relicensing	Various	Various
303.640	Radio Frequency	40	40
302.050	Miscellaneous Intangibles	20	20
303.105	Capitalized Software - 5 year	5	5
303.707	Capitalized Software - 7 year	7	7
303.210	Capitalized Software - 10 year	10	10
303.315	Capitalized Software - 15 year	15	15
Easements			
350	Transmission Easements	60	60
360	Distribution Easements	60	60
389	General Easements	60	60

[67] Refer to WP SCE-09 Vol. 03, Book A, pp. 5-12 (Rate Determination Schedule).

4. <u>Forecast Service Lives – Account-By-Account</u>

a) <u>General Plant</u>

Most general and intangible plant accounts contain many low value individual items. Following FERC guidelines, non-structural items in these accounts are amortized by vintage group over the specified service life and retired at the end of the life span.[68] For example, personal computers are amortized over a 5-year period (*i.e.*, a 20 percent annual depreciation rate) and when a vintage group reaches five years of age, the vintage group of computers will be fully depreciated and retired off the books. Following this approach eliminates costly plant record keeping and continuous physical tracking of the equipment. Over time, imbalances in the accumulated depreciation can occur if there are depreciation life or rate changes and if net salvage is recorded to the books but not reflected in the depreciation rate. These accumulated depreciation surpluses (deficits) are amortized over this GRC cycle (2018-2020).

(1) <u>Account 391.1 – Office Furniture</u>

Account 391.1 contains all costs incurred to acquire office furniture. It includes such items as modular furniture, desks, cabinets, and files used for general utility service that are not permanently attached to buildings. A 20-year average service life is reasonable for both modular and free standing furniture.

(2) <u>Account 391.2 And 391.3 – Computer Equipment</u>

The assets in Account 391.2 can include Central Processing Units and associated components (*e.g.*, monitors, printers, etc.) when purchased as a bundled unit, or when any of these items are purchased individually and meet the capitalization threshold. Account 391.3 is where SCE records all investment related to mainframe computer and file server equipment. SCE information technology personnel state that the average life for this equipment should be five years or less. Retention of the five-year life is reasonable.

(3) <u>Account 391.4 – Power Management System</u>

Account 391.4 contains Supervisory Control and Data Acquisition (SCADA) equipment for controlling and monitoring the SCE electrical system. Contained within this

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[68] FERC Accounting Release Number AR15 provided for the vintage year accounting method allowing companies to amortize vintage groups of assets over their designated service life and subsequently retire them. The FERC accounting release states that "[a]doption- of vintage year accounting will relieve companies from maintaining extensive plant records and will generate efficiencies and costs savings without degrading the quality of plant records and the associated financial reporting."

account are the components making up the Power Management System specifically, computer and data gathering equipment, man-machine interface, analog and digital telemetry devices, and data center facility infrastructure. The account consists of components with very different lives depending upon the technical sophistication and other retirement factors affecting the equipment. SCE's power management personnel have assessed this equipment as having service lives in categories of 5, 7, 10, 15 or 20 years. A dollar weighting of these equipment lives yields a combined average service life of about 10 years. Each of these equipment life categories are summarized in Table III-25 and addressed in the following discussions.

Table III-25
Power Management System Service Life Proposals

CPR Account	Description	2015-2017 Authorized (Years)	2018-2020 Proposed (Years)
Five-Year Power Management System Equipment			
391.417	Firewall	7	5
391.422	TACACS/Sniffer	10	5
391.405	EMS Web Server	20	5
391.406	EMS Workstation	20	5
391.43	External Tape Drive	20	5
Seven-Year Power Management System Equipment			
391.401	Bulk Storage	7	7
391.416	USAT Hub	7	7
Ten-Year Power Management System Equipment			
391.402	Communications Network Processor	10	10
391.404	Server Cabinet	10	10
391.411	Large Screen Display System	10	10
391.419	Dynamic Map Board	25	10
391.42	Data Acquisition Controller	10	10
391.429	Digital Wall Chart Recorded	10	10
391.435	Dial-Up Remote Terminal Unit	10	10
Fifteen-Year Power Management System Equipment			
391.436	Uninterruptible Power Supply	15	15
391.438	Battery System	15	15
Twenty-Year Power Management System Equipment			
391.421	Remote Terminal Unit (RTU)	20	20

(a) Five-Year Power Management System Equipment

Equipment in the 5-year category is typically modern, digital electronic computer and microprocessor-based equipment which is subject to discontinued support by the manufacturer or replaced with newer equipment within a short period of time. Due to these changing needs, the hardware asset portfolio will become obsolete if not actively refreshed, which can significantly affect operations. Furthermore, these devices contain components like processors, memory, and rotating disks that become obsolete and/or worn out after five years of continuous use.

(b) Seven-Year Power Management System Equipment

Equipment in the 7-year category is typically modern, digital electronic computer and microprocessor-based equipment which is subject to discontinued support by the manufacturer or replaced with newer equipment within a short period of time. Furthermore, these devices contain rotating disk, printers and CRTs that become obsolete and/or worn out after seven years of continuous use.

(c) Ten-Year Power Management System Equipment

SCE's power management personnel indicate that the ten-year lived equipment is less sophisticated than the typical 7-year items. They contain digital electronics as well as some electromechanical devices. Most of this equipment is specialized, proprietary and generally supported by the vendor for 10 years. Past experience indicates this equipment will be replaced after about 10 years.

(d) Fifteen-Year Power Management System Equipment

Telemetry equipment is analog devices with mostly repairable parts. They do not contain a high degree of sophistication and with proper maintenance, these devices should last approximately 15 years. The Uninterruptible Power System is an electromechanical device with a rated life of about 15 years. Beyond 15 years both of these devices require high levels of maintenance due to passive component failures and electromechanical malfunction.

(e) Twenty-Year Power Management System Equipment

Twenty-year power management system equipment contains hardened substation field equipment used for data gathering. The equipment is highly fault-tolerant and is typically supported by the vendor for approximately 20 years. Also included here are Wall Strip Chart Recorders and Backup Control Systems. These are robust analog devices containing some passive electronics typically rated for 20 years of service.

(4) Account 391.5 and 391.6 – Office Equipment; Duplicating Equipment

These accounts represent a $7.4 million net investment in miscellaneous office equipment such as video projection equipment, public address equipment, plotters, duplicating equipment, and so forth. The current service life of five years is reasonable.

(5) Account 393 – Stores Equipment

Account 393 represents a $7.6 million net investment in equipment used for the receiving, shipping, handling, and storage of materials and supplies for warehouses. It includes electric pallet jacks, lifting tables, stretch wrapping machine, racking rotobins/storage bins, battery chargers, transformer trays, hand-held scanners, lockers, picking carts, awnings, barrel grabbers, warehouse heaters, screen netting, cable cutting machines, and so forth. Based on historical Stores Equipment usage and knowledge of warehouse equipment, the operational personnel state that this equipment has a useful service life of 20 years or less. Retaining the current 20-year service life is reasonable for this account.

(6) Account 394 – Tools & Work Equipment

Account 394 represents a $49.2 million net investment in tools and equipment for construction, repair, maintenance, general shop, and garage, but not specifically includable in other accounts. SCE proposes retaining the current service life of 10 years.

(7) Account 395 – Laboratory Equipment

Account 395 represents a $63.8 million net investment in laboratory and field test equipment. The account has a wide variety of equipment. It includes, for example, calibrators, baths, furnaces, current shunts, dew point meters, gauge calibrators, insulation testers, gas leak detectors, mass comparator, micrometers, multimeters, oscilloscopes, phase meters, watthour meter testing power source, power system analyzers, self-contained portable calibration carts, sound meters, metrology standards, thermometer, vibration analysis data pack, and volt meters. The expected average service life of lab and test equipment is impacted by two major retirement factors: technological obsolescence and normal "wear and tear" from usage in both the field and lab environments. SCE proposes to retain the currently authorized 15-year average service life for this account.

(8) Account 397 – Telecommunication Equipment

Account 397 represents SCE's investment in communication equipment for the company's system. Contained within this account are the electronic and computer-based equipment (such as transmission equipment, dynamic network multiplexers, data network interconnection system, and radio equipment), as well as communication infrastructure (such as the copper and fiber optic cable, conduit, microwave equipment, and the electrical power generator system). SCE telecommunication engineers have assessed this equipment as having service lives of 5, 7, 10, 15, 25, or 40 years depending on the type of equipment.[69] These are the same service lives the Commission authorized in the prior rate case. The equipment lives are addressed in the following discussions.

(a) Five-Year Communication Equipment

Equipment falling into the 5-year category experiences shorter lives from lack of vendor support, facility relocations, and insufficient capacity to meet current demand.

(b) Seven-Year Communication Equipment

Equipment in the 7-year category is typically modern, state-of-the art, electronic and/or computer-based equipment which is subject to being discontinued by manufacturer or replaced with newer equipment within a short period of years.

(c) Ten-Year Communication Equipment

NetComm radio equipment is not as sophisticated as the other electronic equipment and warrants a 10-year service life. SCE is replacing NetComm radios after about 10 years.

(d) Fifteen-Year Communication Equipment

Equipment in this group of assets is typically subject to environmental wear and has an average life of about 15 years. The equipment fails or is replaced as a result of unreliability and/or high maintenance due to failure of passive components or electromechanical failure. In the case of electronic components included in this category, the telecommunication engineers state that these are relatively basic and not the state-of-the art- electronics reflected in the seven-year life category.

(e) Twenty-Five Year Communication Equipment

Although SCE has not yet had fiber optic cable as long as 25 years, SCE telecommunication engineers believe that it may be subject to greater level of degradation than the copper cable. They estimate that 25 years is a reasonable life for the fiber optic cable.

[69] Refer to WP SCE-09 Vol. 03, Book A, pp. 314-318 (Telecomm. Engineering Data).

(f) Forty-Year Communication Equipment

The balance of the communication infrastructure includes such equipment as overhead and underground communication cable, the communication conduit system, and antenna support structures. This equipment has an average 40-year service life. The items are subject to physical or mechanical deterioration since they are subject to outdoor environments.

(9) Account 398 – Miscellaneous

Account 398 represents a $21.8 million net investment in miscellaneous utility equipment that does not fit other plant accounts. Examples can include such diverse items as kitchen and infirmary equipment. The current service life of 20 years is a reasonable depreciation period for this account.

b) Intangibles

SCE has investments in a number of intangible assets, including hydro relicensing, radio frequencies, long term franchise fees, capitalized software, and land easements and rights-of-way. As previously discussed, the hydro relicensing costs are amortized over the remaining life of the FERC project license period. SCE proposes to continue amortizing the radio frequency investments over the 40-year service life and land easements and rights-of-way over the 60 year service life determined in prior rate case proceedings. The other categories are discussed below.

(1) Miscellaneous Intangibles

The year-end 2015 net investment for miscellaneous intangibles is approximately $431 thousand, which is largely made up of long-term franchise costs (~$300 thousand). SCE proposes to allocate these costs over 20 years.

(2) Capitalized Software

The depreciable life of capitalized software reflects the estimated life prior to investments required to replace or optimize the software as a result of technology, vendor, or business obsolescence. SCE proposes to continue the four existing service life categories of five, seven, ten, and fifteen years determined in prior proceedings.

(3) Easements

SCE proposes to retain the authorized amortization period of 60 years for its easements and rights-of-way.

Appendix A

2016 Service-Life and Net Salvage Study

2016 Service–life and Net Salvage Study

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

foster associates

CONTENTS

August 2016

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a study and recommended service–life statistics and future net salvage rates for transmission, distribution and general depreciable plant owned and operated by Southern California Edison Company (SCE). Foster Associates was engaged by SCE in January 2016. The study was completed in July, 2016.

Foster Associates is a public utility economics consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by SCE were approved by the California Public Utilities Commission (CPUC) in D.15–11–021, dated November 5, 2015. The approved rates were derived from a study conducted on December 31, 2012 plant and depreciation reserve balances. Findings and recommendations developed in the current study are summarized in Section III of this report.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Field visits and discussions with SCE operations and plant accounting personnel;
- Statistical life studies and estimation of projection lives and projection curves; and
- Per unit and moving average net salvage studies and estimation of future net salvage rates.

STUDY PROCEDURE

INTRODUCTION

The purpose of a comprehensive depreciation study for a regulated utility is to analyze the mortality characteristics, net salvage rates and the adequacy of depreciation accruals derived from currently approved depreciation rates. The findings from such an investigation are used in the formulation of revised depreciation rates subject to regulatory approvals.

In the case of the current study, Foster Associates was engaged by SCE to only study and recommend service–life statistics and future net salvage rates in compliance with CPUC directives in D.15–11–021. SCE would then incorporate the recommendations in depreciation rates developed by the Company.

Regarding the directives in D.15–11–021, the CPUC directed SCE to provide full explanations of the quantitative or qualitative base for the application of judgment in future depreciation showings. The Commission further directed the Company to provide:

1. A quantitative discussion of historical and future COR on a per unit basis for the large (greater than 15% as measured by the portion of plant balance) asset classes in the account. This should identify and explain the key factors in changing or maintaining the per–unit COR.
2. Quantitative discussion of historical and future retirement mix; identifying and explaining the key factors in changing or maintaining this mix.
3. Quantitative discussion of asset life and original cost of assets being retired, in relation to the COR, on both a historical and prospective basis. This discussion should be integrated with and/or cross–reference the proposal for life characteristics.
4. An account–specific discussion of the process for allocating costs to COR.

SCOPE

The steps involved in conducting the depreciation study can be grouped into three major tasks:

- Data Collection;
- Life Analysis and Estimation; and
- Net Salvage Analysis and Estimation.

The scope of the 2016 service–life and net salvage study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by SCE provides aged transactions for all plant accounts.

Service life statistics estimated in the 2016 study were derived from plant accounting transactions recorded over the period 2002 through 2015. Detailed accounting transactions were extracted from the Continuing Property Record (CPR) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The accuracy and completeness of the assembled database was verified for activity years 2002 through 2015 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Age distributions of surviving plant at December 31, 2015 were reconciled to the CPR.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

It is important to note what is being estimated in a service life study. It is not unit-years of service; it is dollar–years of service. Retirements are not recorded for plant accounting purposes in units such as feet, pounds, segments or any similar physical measurement. Plant records are maintained in dollars and service lives are measured in dollar–years of service. Estimating service lives based on engineering studies of how long, on average, units of property might remain in service is not equivalent to estimating dollar–years of service.

The size of a retirement unit also matters. A company that defines a span of conductor between supports to be a retirement unit will measure longer service lives than a company that defines one foot of conductor as a retirement unit. Replacement of conductor less than a retirement unit is charged to operating expense and no retirement is recorded for the replaced unit. Larger units result in less frequent recorded retirements, which translate to longer average dollar–years of service.

An added dimension of complexity is introduced when retirements occur at varying ages, attributable to mixed forces of retirement. This creates a non-homogeneous account composed of two subpopulations acted upon by differing forces of retirement. The estimated projection life for such an account measured in dollar–years of service will converge toward the mean of the subpopulation most resistant to the forces of retirement.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements over the period 2002–2015 was available for all plant accounts included in the 2016 study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called “retirement ratio” (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life for each plant account. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, poles and conductors), the concept of retirement dispersion is interpreted differently for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All depreciable plant accounts classified in transmission, distribution and general were studied as full mortality categories in the 2016 study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a reasonable basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was conducted in the 2016 study for transmission, distribution and general plant categories to aid in: a) estimating a realized net salvage rate; b) detecting the emergence of historical trends; and c) establishing a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were also considered in the estimation of future net salvage rates.

In compliance with the CPUC directive in D.15–11–021, per unit net salvage analyses were conducted for the nine (9) plant accounts listed in Table 1 below.

Account Description
354.00 Towers and Fixtures
355.00 Poles and Fixtures
356.00 Overhead Conductors and Devices
364.00 Poles, Towers and Fixtures
365.00 Overhead Conductors and Devices
366.00 Underground Conduit
367.00 Underground Conductors and Devices
368.00 Line Transformers
369.00 Services

Table 1. Per Unit Net Salvage Accounts

Each of the nine plant accounts was grouped into one or more subpopulations of major equipment categories. Historical per unit ratios (defined as net cost per unit to retire divided by the cost per unit to install) were used in both a historical and future per unit analyses. Net costs to retire (or net salvage) were used in the analysis to maintain consistency with future net salvage parameters used in the formulation of remaining–life accrual rates.

Future per unit ratios were derived using an average of the subpopulation net salvage per unit values recorded over the period 2009–2015. These values appear in the numerator of future per unit ratios.

The per unit cost of plant additions used in forecasting future net salvage rates was obtained by dividing vintaged plant in service at December 31, 2015 (*i.e.*, age distributions of surviving plant) by vintaged units in service within each subpopulation. The ratio of average net salvage per unit experienced over the period 2009–2015 (adjusted for inflation) to the per unit cost of plant in service is the ratio that was applied to forecasted retirements to estimate future net salvage for each vintage. The sum of future net salvage over all vintages divided by current plant account balances produces an estimated future net salvage rate for each primary account.

RECOMMENDATIONS AND ANALYSIS

RECOMMENDATIONS

Table 2 below provides a summary of current and recommended projection lives, projection curves and future net salvage rates estimated for SCE in the 2016 study.

Account Description	Current			Recommended		
	P-Life	Dispersion	Sf %	P-Life	Dispersion	Sf %
A	C	D	E	F	G	H
Transmission Plant						
352.00 Structures and Improvements	55.00	S3	-35.0	55.00	L1	-35.0
353.00 Station Equipment	45.00	R0.5	-15.0	40.00	L0.5	-10.0
354.00 Towers and Fixtures	65.00	R5	-60.0	65.00	R5	-185.0
355.00 Poles and Fixtures	50.00	R0.5	-72.0	65.00	SC	-499.0
356.00 Overhead Conductors and Devices	61.00	R3	-80.0	61.00	R3	-210.0
357.00 Underground Conduit	55.00	R3	0.0	55.00	R3	0.0
358.00 Underground Conductors and Devices	40.00	R2.5	-15.0	45.00	S1	-25.0
359.00 Roads and Trails	60.00	SQ	0.0	60.00	R5	0.0
Distribution Plant						
361.00 Structures and Improvements	42.00	R2.5	-25.0	50.00	L0.5	-30.0
362.00 Station Equipment	45.00	R1.5	-25.0	65.00	L0.5	-50.0
364.00 Poles, Towers and Fixtures	47.00	L0.5	-210.0	55.00	R1	-488.0
365.00 Overhead Conductors and Devices	45.00	R0.5	-115.0	55.00	R0.5	-538.0
366.00 Underground Conduit	59.00	R3	-30.0	59.00	R3	-401.0
367.00 Underground Conductors and Devices	45.00	R0.5	-60.0	43.00	R1.5	-261.0
368.00 Line Transformers	33.00	R1	-20.0	33.00	S1.5	-47.0
369.00 Services	45.00	R1.5	-100.0	45.00	R1.5	-387.0
370.00 Meters	20.00	R3	-5.0	20.00	R3	0.0
373.00 Street Lighting and Signal Systems	40.00	L0.5	-30.0	48.00	L1	-100.0
General Plant						
390.00 Structures and Improvements	38.00	R3	-5.0	45.00	R0.5	-10.0

Table 2. Service Life and Net Salvage Parameters

ANALYSIS

A description of each account examined in the 2016 study and factors considered in the estimation of recommended service life and net salvage parameters is contained in the following pages of this report.

TRANSMISSION PLANT
ACCOUNT: 352.00 – STRUCTURES AND IMPROVEMENTS

DESCRIPTION

This account includes the cost in structures and improvements used in connection with transmission operations. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	55-S3	55-L1
Future NS Rate	-35.0%	-35.0%
Realized NS	-13.3%	
Average Age (yrs.)	8.6	
Derived Additions	$717,577,812	
Plant Retirements	$30,750,408	
Percent Retired	4.5%	
Plant Balance	$686,827,404	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Major forces of retirement for this account include system upgrades, severe storms and earthquakes, traffic and fire accidents, rodent damage, automation, revisions in policy, code, and criteria, and wear and tear related to aging.

The statistical service life indications for the full account are derived from unlikely recurring retirement activity. Retirements of $22.9M reported in 2009, constituting 75 percent of the total retirements over the 14–year study period, were related to the retirement of equipment at the Sylmar substation. Average service life indications from the statistical service life analysis range from the low 30s to the mid–50s for bands with lower censoring and conformance indexes. The majority of second– and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each subpopulation are shown in Table 2 below.

The variability of subpopulation service lives is an indication of a nonhomogeneous plant account with mixed forces of retirement acting on the subpopulations. Heterogeneity coupled with high degrees of censoring reduces the level of confidence that can be placed in service–life indications obtained from either a subpopulation or total account analysis.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Foundations	178,220,072	26	85-L1	38.5
MEER Building	159,486,338	23	130-R0.5	73.4
Water Supply	107,675,420	16	103-R3	82.8
Alarm & Monitoring	45,931,434	7	194-S6	99.4
Power Lighting	30,490,714	4	107-L0.5	71.9
HVAC	12,046,998	2	38-L0	7.7
Non-unitized	120,611,640	18		
Miscellaneous	32,364,788	5	30-L0.5	3.7
Total	686,827,404	100	107	

Table 2. Major Structural Components

Life Estimation

Based mainly on the first–degree statistical service–life indications, thereby rejecting origin–modal dispersions in which chance is a more pervasive force of retirement, a 55–L1 projection life–curve is recommended for this account. This recommendation retains the currently approved projection life and adjusts the projection curve to reflect lower modal curves observed in the subpopulation analysis. The recommendation also reflects a lack of evidence for adjusting the service life estimates given the single retirement underlying a significant percentage of the retirement history. Foster Associates was informed that Company engineers and operations personnel do not anticipate policy or procedural changes or technological advances that would introduce significantly different forces of retirement from those observed in the past.

Net Salvage Analysis

The adjusted historical net salvage analysis for this account exhibits an overall realized net salvage rate of –13.3 percent from $31M of retirement activity over the period 2002–2015. More recent 5–year moving average bands indicate realized negative net salvage exceeding –87 percent.

Net Salvage Estimation

Based on this historical experience and the expectation of continuing removal costs when these facilities are retired, retention of a –35 percent future net salvage rate is recommended for consideration by SCE. As in the service life estimation, this recommendation reflects lack of evidence for adjusting future net salvage estimates given the single retirement underlying a significant percentage of the retirement history in this account.

TRANSMISSION PLANT
ACCOUNT: 353.00 – STATION EQUIPMENT

DESCRIPTION

This account includes the cost in transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	40-L0.5
Future NS Rate	-15.0%	-10.0%
Realized NS	0.6%	
Average Age (yrs.)	10.3	
Derived Additions	$5,785,827,668	
Plant Retirements	$538,115,861	
Percent Retired	10.3%	
Plant Balance	$5,247,711,807	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Retirement activity in transmission station equipment is largely associated with age, obsolescence and growing or shifting loads that necessitate rebuilding to larger capacities. Company engineers report that thermal, mechanical, and electrical integrity issues intensify with age typically beginning around age 30 years when insulation degradation, increased in–service failures, and increased maintenance arises. Retirements occur when increased costs and decreased utilization rates dictate is it no longer economic to repair such equipment. Decreased spare parts availability as equipment ages also plays a major role in age–related retirements.

The Company utilizes a Condition Based Maintenance (CBM) approach to manage all transformers and circuit breakers by routinely conducting off–line diagnostics, visual inspections, and functional checks. These analysis components are combined with other key data such as age, design, moisture levels, loading, and fault exposure to develop a health index ranking that is maintained throughout the life of these assets and used in the determination of when to repair or retire.

Average service life indications from the statistical analysis of the full account range from the low 30s to the low–40s for bands with lower censoring and conformance indexes. The majority of second– and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Transformers	1,068,594,714	20	41-SC	7.6
Circuit Breakers	631,804,488	12	32-L1.5	0.8
Switches & Switch Gear	520,013,661	10	34-L0	10.4
Control & Monitoring Devices	478,204,337	9	50-L0	-
Bus Support Structures	439,776,382	8	63-R0.5	27.5
Capacitors	309,258,912	6	49-L1	0.6
Power Control Cable	267,340,154	5	51-SC	30.6
Foundations	151,926,940	3	70-L1	34.5
Non-unitized	790,758,849	15		
Miscellaneous	590,033,371	11	36-L0.5	11.2
Total	5,247,711,807	100	44	

Table 2. Major Structural Components

The subpopulation analysis of the full historical experience exhibits a range of average service lives between 32 and 63 years with a direct–dollar–weighted average of 44 years and a preponderance of lower–left modal dispersions. Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of these subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on indications from both the full account and subpopulation statistical service life analyses, a 40–L0 projection life–curve is recommended for this account. This recommendation is derived from account total service lives indicated for trials with lower censoring, conformance indexes, and hazard functions uncompromised by declining or negative hazard rates. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –12.7 percent, a composite of an 8.2 percent gross salvage rate and a 20.9 percent cost of retiring rate. The most recent 5–year rolling average indicates a –26.4 percent realized net salvage rate.

Net Salvage Estimation

Minimal gross salvage, generally from scrap metal and recycling, is expected from the retirement of this equipment. Significant cost of retiring, however, is expected in the form of labor and equipment such as cranes. The adjusted historical net salvage experience provides the basis for recommending a –10 percent future net salvage rate for consideration by SCE. This recommendation reflects discounting indications obtained from small retirements and large cost of removal recorded in 2015 and focusing more on activity years 2009−2014. The –12.7 realized net salvage rate and –26.4 percent realized net salvage rate observed for the most recent 5–year rolling band are somewhat distorted by the 2015 activity, which is not considered indicative of future expectations.

TRANSMISSION PLANT
ACCOUNT: 354.00 – TOWERS AND FIXTURES

DESCRIPTION

This account includes the cost installed of towers and appurtenant fixtures used for supporting overhead transmission conductors. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	65-R5	65-R5
Future NS Rate	-60.0%	-185.0%
Realized NS	-799.7%	
Average Age (yrs.)	9.3	
Derived Additions	$2,264,446,057	
Plant Retirements	$4,473,231	
Percent Retired	0.2%	
Plant Balance	$2,259,972,826	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Forces of retirement acting upon transmission towers and fixtures include line upgrades, corrosion, relocation (for lower voltage structures), and failures due to wind storms, ice, or floods. Most of these forces tend to increase with age. Although storm damage can generally be expected to impact retirements at any age, in combination with deterioration, the probability of failure is cumulative. SCE performs annual inspections on all transmission towers and performs subsequent maintenance identified from those inspections.

The statistical service life indications for the full account are derived from minimal and irregular retirement activity. Retirements recorded in this account amount to only $4.5M from an average plant balance exceeding $1.3B over the study period and less than 0.2 percent of derived additions. Statistical service life indications derived from this minimal experience are highly censored, unrealistically long (approaching 200 years), and contrary to Company expectations of the future age of tower retirements.

The distribution of major categories of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Towers	1,139,621,027	50	132-S2	71.6
Non-unitized	1,018,898,065	45		
Other	101,453,734	4	178-R2.5	82.2
Total	2,259,972,826	100	136	

Table 2. Major Structural Components

The subpopulation analysis is also highly censored and does not produce interpretative life indications. The account could not be reasonably sub–divided into more than three subpopulations with miscellaneous items constituting only four percent and non–unitized items constituting 45 percent of the investment.

LIFE ESTIMATION

The minimal retirement activity and resulting unreliable service life indications from both the full account and subpopulation statistical analyses do not provide a strong foundation for service–life estimation. Foster Associates, therefore, deferred to SCE in recommending the currently approved 65–R5 projection life–curve. Factors evaluated by SCE beyond the service–life analyses include operational, accounting and ratemaking considerations.

NET SALVAGE ANALYSIS

The adjusted net salvage analysis for this account indicates an overall net salvage rate of –799.7 percent realized from $4.5M of retirements recorded over the period 2002–2015. However, as noted above, total retirements are less than 0.2% of derived additions.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –104 and –185 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Although minimal gross salvage, generally from scrap, is expected from these assets, significant costs of retiring and removing (attributable to labor costs and cost of equipment such as cranes used in the retirement process) are expected to be incurred in the future. Based on the above analysis, a future net salvage rate of −185 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 355.00 – POLES AND FIXTURES

DESCRIPTION

This account includes the installed cost of transmission line poles, wood, steel, concrete, or other material, together with appurtenant fixtures used for supporting overhead transmission conductors. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	50-R0.5	65-SC
Future NS Rate	-72.0%	-499.0%
Realized NS	-155.5%	
Average Age (yrs.)	10.1	
Derived Additions	$1,073,636,145	
Plant Retirements	$65,068,786	
Percent Retired	6.5%	
Plant Balance	$1,008,567,359	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of wood poles in the Company's system are full–length and "through–boring" treated to protect against decay and insect attack. Wood poles may also be treated with a steel stub or a fiberglass wrap to provide additional support. In addition to pole treatment, the Company conducts a 10–year inspection cycle to address safety and reliability. Tree trimming and vegetation management are also a significant component of reliability measures undertaken by the Company.

Major forces of retirement acting upon transmission wood poles include external, internal, top rot, and split top deterioration. Additional forces include vehicles, wind, storm, fire, and bird (mainly woodpecker) damage. Response to these forces partly depends on the specific locale of the pole given the Company's wide geographical area encompassing mainly desert but also agricultural, rural, and urban communities.

Indications from the statistical service life analysis for this account range from the mid–60s to the low–80s for bands with lower censoring and conformance indexes. The majority of third–degree polynomial indications are considered less reliable than first–degree or second–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Eng. Light Duty Steel, Concrete	419,049,403	42	84-L0.5	57.2
Wood/Fiberglass/Composite	375,781,560	37	57-SC	29.6
Non-Unitized	212,474,639	21		
Other	1,261,756	0	46-S4	53.5
Total	1,008,567,359	100	71	

Table 2. Major Structural Components

The subpopulation analysis indicates service lives ranging between 46 and 84 years with an average of 71 years. It is the opinion of Foster Associates that service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on the first–degree and second–degree indications of the full account analysis and observations from the subpopulation analysis, a 65–SC projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall realized net salvage rate of –155.5 percent and a –242.5 percent rate for the most recent five–year rolling band. Five–year rolling bands indicate negative net salvage rates exceeding –100 percent for 8 of the 11 analyzed bands.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –90 and –499 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −499 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 356.00 – OVERHEAD CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of overhead conductors and devices used for transmission purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	61-R3	61-R3
Future NS Rate	-80.0%	-210.0%
Realized NS	-284.3%	
Average Age (yrs.)	13.7	
Derived Additions	$1,500,210,639	
Plant Retirements	$18,103,015	
Percent Retired	1.2%	
Plant Balance	$1,482,107,624	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Forces of retirement acting upon transmission conductors include deterioration resulting from atmospheric corrosion, fatigue failure due to conductor vibration, storm damage, failure of splices or dead–ends, relocation (*e.g.*, highway widening, damsite construction, etc.), circuit upgrades, system reconfiguration and idle facilities (*e.g.*, closure of generation facilities or loss of large customers).

The statistical service life analysis for this account indicates average service lives exceeding 85 years. The analysis, however, is based on $18M of retirement activity from derived additions exceeding $1.5B. Retirement activity of 1.2 percent of derived additions is not considered sufficient to provide a reliable basis for service life estimation.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 is shown in Table 2. More than 40 percent of the classified investment is conductor larger than 1500 MCM. Service life indications obtained from a full–band statistical analysis of the major categories are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Conductor > 220 kV	739,015,019	50	106-R3	57.7
Conductor < 220 kV	202,769,129	14	82-R1.5	84.0
Switches	27,761,688	2	39-R1	2.5
Non-Unitized	399,410,246	27		
Other	113,151,541	8	199-SQ	100.0
Total	1,482,107,623	100	110	

Table 2. Major Structural Components

The subpopulation analysis of the full historical experience evidences a range of average service lives between 39 and 199 years with a dollar–weighted average of 110 years. These indications are compromised by high censoring and minimal retirement activity comparable to observations in the full account.

LIFE ESTIMATION

With consideration given to the minimal retirement experience in this account and the resulting extremes in service life indications, Foster Associates deferred to the Company in recommending retention of the currently approved 61–R3 projection service–life parameters.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –284.3 percent. However, as noted above, this history is based on relatively minimal retirement activity over the period 2002–2015.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –114 and –210 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −210 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

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TRANSMISSION PLANT
ACCOUNT: 357.00 – UNDERGROUND CONDUIT

DESCRIPTION

This account includes the installed cost of underground conduit and tunnels used for housing transmission cables or wires. Account statistics and current and proposed parameters are shown in Table 1.

	Current	Proposed
Plife-Curve	55-R3	55-R3
Future NS Rate	0.0%	0.0%
Realized NS	-69.5%	
Average Age (yrs.)	15.6	
Derived Additions	$61,474,359	
Plant Retirements	$387,297	
Percent Retired	0.6%	
Plant Balance	$61,087,062	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Rebuild and digging are the major forces of retirement expected to affect this account. The statistical service–life analysis for the full account is based on highly censored trials (87 percent) with life indications ranging between 88 and 146 years. Only $387,297 or 0.6% of derived additions has been retired from the account.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Conduit	34,334,761	56	130-S1.5	86.3
Manholes and Vaults	17,239,213	28	65-S2	81.1
Trenches	2,063,079	3		N/A
Non-unitized	7,410,219	12		
Other	39,791	0		N/A
Total	61,087,062	100	108	

Table 2. Major Structural Components

Subpopulation service life indications are similarly derived from highly censored trials providing little insight into future live expectancies.

LIFE ESTIMATION

Neither the full account nor the subpopulation analysis is considered to provide sufficient evidence to support adjusting the currently approved 55–R3 projection life and curve. Current parameters are, therefore, recommended to be retained for this account.

NET SALVAGE ANALYSIS

The adjusted net salvage analysis for this account indicates an overall net salvage rate of –69.5% percent realized from minimal retirement activity of only $387,297.

NET SALVAGE ESTIMATION

The historical net salvage experience is considered insufficient to support an adjustment to the currently approved zero percent future net salvage rate. The current rate is, therefore, recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 358.00 – UNDERGROUND CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of underground conductors and devices used for transmission purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	40-R2.5	45-S1
Future NS Rate	-15.0%	-25.0%
Realized NS	-27.0%	
Average Age (yrs.)	11.6	
Derived Additions	$284,995,149	
Plant Retirements	$16,382,826	
Percent Retired	6.1%	
Plant Balance	$268,612,323	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Deterioration, failure, relocations, upgrades and accidental dig–ins are the major forces of retirement acting upon underground conductors. The statistical life analysis conducted for this account indicates average service lives between the mid–30s and mid–40s for trials with lower censoring, conformance indexes, and non–negative retirement ratios.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Conductor	163,955,728	61	45-S1.5	51.1
Potheads	27,568,689	10	29-S2	5.2
Arresters	19,845,390	7	31-S1.5	2.0
Cathodic Protection	12,086,839	4	39-R1	81.4
Non-unitized	45,155,677	17		
Total	268,612,323	100	41	

Table 2. Major Structural Components

An analysis of the subpopulations indicates a range of service lives between 29 and 45 years with lower modal dispersions and an average of 41 years. Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 45–S1 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –27 percent realized from $16M of retirement activity over the period 2002–2015. Five–year rolling bands are relatively stable and range between –14.4 and –49.7 percent. The most recent 5–year rolling band indicates a realized average net salvage rate of –30.6 percent.

NET SALVAGE ESTIMATION

Based on the analysis observations, a –25 percent future net salvage rate is recommended for consideration by SCE. Consideration was given in this recommendation to both the –27 historical average realized net salvage rate and the likelihood of more negative future net salvage given recent experience such as the –30.6 percent realized net salvage rate observed for the most recent 5–year rolling band.

TRANSMISSION PLANT
ACCOUNT: 359.00 – ROADS AND TRAILS

DESCRIPTION

This account includes the cost of roads, trails, and bridges used primarily as transmission facilities. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	60-SQ	60-R5
Future NS Rate	0.0%	0.0%
Realized NS	-314.1%	
Average Age (yrs.)	5.1	
Derived Additions	$194,172,555	
Plant Retirements	$154,514	
Percent Retired	0.1%	
Plant Balance	$194,018,041	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The statistical service life analysis for this account is based on minimal retirement activity of $154,514, or 0.1 percent of derived additions from an average plant balance exceeding $108M over the period 2002–2015. Retirements were reported in only 3 years during that period. The service life analysis is highly censored at more than 76.8 percent with resulting life indications ranging between 95 and 175 years.

LIFE ESTIMATION

Statistical service life indications for this account are considered insufficient to warrant an adjustment to the currently approved projection life. The current SQ projection curve, however, is considered extreme given the historical experience and the likelihood of more dispersed retirements. Based on these observations and considerations, a 60–R5 projection life–curve is recommended for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates a realized net salvage rate of –314.1 percent from retirements recorded in 2010, 2012, and 2013 only.

NET SALVAGE ESTIMATION

The underlying retirement experience in the historical net salvage analysis is not considered sufficient to warrant adjusting the currently approved zero percent future net salvage. Retention of the current rate is, therefore, recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 361.00 – STRUCTURES AND IMPROVEMENTS

DESCRIPTION

This account includes the cost in place of structures and improvements used in connection with distribution operations. The account comprises mainly control houses and related structures at distributions substations. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	42-R2.5	50-L0.5
Future NS Rate	-25.0%	-30.0%
Realized NS	-33.1%	
Average Age (yrs.)	13.8	
Derived Additions	$632,396,471	
Plant Retirements	$55,690,492	
Percent Retired	9.7%	
Plant Balance	$576,705,979	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Major forces of retirement for this account include system upgrades, severe storms and earthquakes, traffic and fire accidents, rodent damage, automation, revisions in policy, code, and criteria, and wear and tear related to aging.

Statistical service life indications for this account range from the low–40s to low–60s for bands with lower censoring and conformance indexes. The majority of second and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Foundation etc.	112,919,451	20	28-S4	76.6
MEER Building	102,746,634	18	38-S1.5	80.8
Water Supply	50,908,790	9	41-S1.5	74.6
Power Lighting	45,421,111	8	39-S3	92.0
HVAC	33,804,236	6	35-R2	72.5
Alarm & Monitoring	16,557,229	3	29-S3	84.1
Non-unitized	39,863,694	7		
Other	174,484,836	30	60-O3	29.4
Total	576,705,980	100	43	

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives ranging between 29 and 60 years, various dispersions, and a dollar–weighted mean of 43 years.

Life Estimation

Based on these observations and ignoring origin–modal dispersions in which chance is a more pervasive force of retirement, a 50–L0.5 projection life–curve is recommended for this account.

Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category. Company operations personnel do not expect policy or procedural changes or technological advances that would introduce significantly different forces of retirement from those observed in the past.

Net Salvage Analysis

The historical net salvage analysis for this account indicates an adjusted overall net salvage rate of –33.1 percent realized from $55,690,492 of retirement activity over the period 2002–2015. Five–year rolling band rates have not been less negative than –21.3 percent during that period and the five–year band ending in in 2015 shows a –44.2 percent net salvage rate.

Net Salvage Estimation

Based on these observations and considerations, a –30 percent future net salvage rate is recommended for consideration by SCE. It is considered unlikely that the upward trend in cost of removal will reverse in the near future.

DISTRIBUTION PLANT
ACCOUNT: 362.00 – STATION EQUIPMENT

DESCRIPTION

This account includes the installed cost of station equipment, including transformer banks, used for the purpose of changing the characteristics of electricity in connection with its distribution. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R1.5	65-L0.5
Future NS Rate	-25.0%	-50.0%
Realized NS	-46.5%	
Average Age (yrs.)	13.1	
Derived Additions	$2,382,404,227	
Plant Retirements	$138,133,698	
Percent Retired	6.2%	
Plant Balance	$2,244,270,529	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The statistical service life analysis for this account indicates average service lives within a narrow range between the mid–50s and mid–60s for bands with lower censoring and conformance indexes.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	Investment %	Full Band PLife-Curve	Censoring (%)
Transformers	359,814,116	16	56-L1	81.9
Monitoring Devices	275,879,081	12	34-R2	61.6
Circuit Breakers	270,107,330	12	45-S0.5	81.3
Bus Support	182,345,026	8	75-L0.5	90.1
Power Control Cable	115,539,624	5	42-L1	75.7
Switches	95,098,077	4	52-L1	81.7
Non-unitized	394,553,141	18		
Other	550,934,134	25	64-L0.5	19.7
Total	2,244,270,528	100	54	

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives between 34 and 75 years with lower modal dispersions and a dollar–weighted mean of 54 years.

Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 65–L0.5 projection life–curve is recommended for this account. This recommendation is within the range of both full account and subpopulation service life indications. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

Although not equivalent to dollar–years of service, SCE engineers estimate a mean time to wear–out of about 37 years for A–Bank (200 kV) transformers and about 57 years for B–Bank (115 or 66 kV) transformers. The number of transformers in service at year–end 2015 was 158 A–Bank and 2,226 B–Bank. Company engineers also estimate that the mean time to wear–out of mainline and radial oil switches is about 35 years and about 49 years for circuit breakers. The average age of transformers measured in unit−years is about 26 years whereas the average age measured in dollar–years is about 10 years. Similarly, the average age of circuit breakers measured in unit−years is about 32 years whereas the average age measured in dollar–years is about 10 years.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –46.5 percent, realized from $138,133,698 of retirement activity and 5.8 percent of derived addition over the period 2002–2015. Most recent 5–year rolling bands ending in 2013, 2014,and 2015 exhibit net salvage rates of –47.2, –65.6 and –81.4 percent respectively.

NET SALVAGE ESTIMATION

Based on these observations and the expectation of continuing negative net salvage, a –50 percent future net salvage rate is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 364.00 – POLES, TOWERS AND FIXTURES

DESCRIPTION

This account includes the installed cost of poles, towers, and related fixtures used for supporting overhead distribution conductors and service wires. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	47-L0.5	55-R1
Future NS Rate	-210.0%	-488.0%
Realized NS	-505.0%	
Average Age (yrs.)	11.3	
Derived Additions	$2,608,099,972	
Plant Retirements	$144,713,616	
Percent Retired	5.9%	
Plant Balance	$2,463,386,356	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of wood poles in the Company's system are full–length and "through–boring" treated to protect against decay and insect attack. Wood poles may also be treated with a steel stub or a fiberglass wrap to provide additional support. In addition to pole treatment, the Company conducts a 10–year inspection cycle to address safety and reliability. Tree trimming and vegetation management are also a significant component of reliability measures undertaken by the Company.

As with transmission wood poles, major forces of retirement acting upon distribution wood poles include external, internal, top rot, split top deterioration and pole loading. Additional forces include vehicles, wind, storm, fire, and bird (mainly woodpecker) damage. Response to these forces partly depends on the specific locale of the pole given the Company's wide geographical area encompassing mainly desert but also agricultural, rural, and urban communities.

The statistical service life analysis for this account indicates consistent indications with average service lives around the mid–50s for bands with lower censoring and conformance indexes.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

An analysis of the single subpopulation of poles indicates a 53–R1 projection life–curve at 46 percent censoring. This indication is comparable to indications obtained for the full band statistical service life analysis.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Poles	2,191,572,261	89	53-R1	46.0
Non-unitized	271,814,095	11		
Total	2,463,386,356	100	53	

Table 2. Major Structural Components

Life Estimation

Based on these indications of a slightly longer projection life than currently approved, a 55–R1 projection life–curve is recommended for this account.

Net Salvage

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –505.0 percent, realized from $144.7M of retirement activity constituting 5.5 percent of derived addition over the period 2002–2015. More recent 5–year rolling bands ending in 2013, 2014,and 2015 exhibit negative net salvage rates exceeding –600 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –180 and –488 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and three percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

Net Salvage Estimation

Based on the above analysis, a future net salvage rate of −488 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 365.00 – OVERHEAD CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the cost installed of overhead conductors and devices used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	55-R0.5
Future NS Rate	-115.0%	-538.0%
Realized NS	-206.4%	
Average Age (yrs.)	16.7	
Derived Additions	$1,571,387,374	
Plant Retirements	$138,400,064	
Percent Retired	9.7%	
Plant Balance	$1,432,987,310	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Rebuild programs and relocation to address changes in capacity and rights of way, deterioration resulting from atmospheric corrosion, fatigue failure due to conductor vibration, storm damage, and splice failure are the major forces of retirement acting upon this plant category. Lightning strikes also nick the conductor, reducing its capacity and eventually causing burndown. Although repair at the damaged point is possible with splicing and reconnecting, it is costly. It is common, therefore, to remove and replace a longer section of the damaged conductor, which is usually the span between supports. Overhead to underground facilities conversion, such as that governed by CPUC Rule 20, continues to be a force of retirement acting upon this account.

The statistical service life analysis for this account is based on moderately censored trials with censoring exceeding 47 percent. A number of first and second–degree polynomials indications derived from graduated hazard rates that are unrealistically declining or zeroed were rejected. Origin–modal dispersions in which chance is a more pervasive force of retirement were also rejected. More consistent indications for bands with lower censoring and conformance indexes indicated average service lives between 36 and 65 years and lower modal dispersions.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below. Equipment classified in the "Other" category includes primarily circuit breakers and fuse holders.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Overhead Conductor	946,696,334	66	70-R0.5	65.3
Switches	347,104,388	24	42-S0	26.7
Non-unitized	52,173,406	4		
Other	87,013,183	6	24-O3	3.8
Total	1,432,987,311	100	60	

Table 2. Major Structural Components

An analysis of the subpopulations indicates service lives between 24 and 70 years with lower modal dispersions and a dollar–weighted average of 60 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the sub-population indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 55–R0.5 projection life–curve is recommended for this account based upon the more consistent indications for bands with lower censoring and conformance indexes in both the full account and subpopulation statistical service−life analysis.

Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category. Although not equivalent to dollar–years of service, SCE engineers estimate the mean time to wear–out of an overhead capacitor bank is about 30 years. Approximately 11,388 capacitor banks were installed in the overhead system at year–end 2015.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –206.4 percent realized from $138,400,064 of retirement activity constituting 8.8 percent of derived addition over the period 2002–2015. More recent 5–year rolling bands ending in 2013, 2014,and 2015 show negative net salvage rates exceeding –300 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –195 and –538 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and three percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −538 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 366.00 – UNDERGROUND CONDUIT

DESCRIPTION

This account includes the installed cost of underground conduit and tunnels used for housing distribution cables or wires. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	59-R3	59-R3
Future NS Rate	-30.0%	-401.0%
Realized NS	-183.1%	
Average Age (yrs.)	14.2	
Derived Additions	$1,848,035,134	
Plant Retirements	$36,174,527	
Percent Retired	2.0%	
Plant Balance	$1,811,860,607	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Conduit failures are generally the result of mechanical damage caused by excavating or drilling crews inadvertently digging into or drilling through the duct. The statistical service life analysis for this account is based on highly censored trials with indicated average service lives exceeding 70 years. Additionally, only minimal retirement activity of $36M from derived additions exceeding $1.8B has been reported. Constituting 2.0 percent of derived additions, this retirement activity is considered insufficient to provide a reliable basis for service life estimation.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Conduit	789,932,796	44	93-S3	93.0
Pull and Slab Boxes	447,741,061	25	50-S2	50.5
Vaults	324,651,530	18	79-S2	80.6
Excavation Trenches	16,836,983	1	184-R4	100.0
Non-unitized	75,629,378	4		
Other	157,068,859	9	49-L1	45.0
Total	1,811,860,607	100	76	

Table 2. Major Structural Components

Equipment classified in the "Other" category includes primarily risers, manholes, and blower assemblies.

As noted with the full account analysis, high censoring of the subpopulations also produces indeterminate service life indications.

LIFE ESTIMATION

With consideration given to the minimal retirement experience in this account and the resulting unreliable service–life indications, Foster Associates deferred to the Company in recommending retention of the currently approved 59–R3 projection service–life parameters.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –183.1 percent. As noted above, however, this history provides minimal retirement activity over the period 2002–2015.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –108 and –401 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions..

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −401 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 367.00 – UNDERGROUND CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of underground conductors and devices used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	43-R1.5
Future NS Rate	-60.0%	-261.0%
Realized NS	-155.7%	
Average Age (yrs.)	11.0	
Derived Additions	$5,946,990,287	
Plant Retirements	$398,585,960	
Percent Retired	7.2%	
Plant Balance	$5,548,404,327	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of SCE's underground cable population is XLPE, which generally fails due to breakdown of insulation over time. The statistical service life analysis for this account indicates average service lives in a narrow range between 40.5 and 44.7 years with lower modal dispersions for trials with lower censoring, conformance indexes, and hazard functions not compromised by negative or declining rates.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Cable	4,452,641,073	80	45-R2	18.6
Non-unitized	288,856,647	5		
Other	809,879,908	15	27-L1	18.1
Total	5,551,377,628	100	42	

Table 2. Major Structural Components

Equipment classified in the "Other" category includes primarily circuit breakers and switches.

An analysis of the subpopulations indicates a 27–L1 and a 45–R2 service life curves with lower modal dispersions and a dollar–weighted mean of 42 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 45–R1.5 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

Although not equivalent to dollar–years of service, SCE engineers estimate a mean time to failure (MTTF) of 41 years for cross–linked polyethylene (XLPE) and 46 years for tree retardant cross–linked polyethylene (TR–XLPE) conductor. Company engineers also estimate that the mean time to wear–out of underground mainline and radial oil switches is about 35 years and the mean time to wear–out of an underground capacitor bank is about 30 years and 25 years for automatic reclosers. Approximately 11,549 subsurface oil–filled switches, 2,253 capacitor banks and 47 automatic reclosers were installed in the underground system at year–end 2015.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –155.7 percent realized from $398,585,960 of retirement activity constituting 6.7 percent of derived addition over the period 2002–2015. The most recent four 5–year rolling bands show negative net salvage rates exceeding –150 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –112 and –261 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −261 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 368.00 – LINE TRANSFORMERS

DESCRIPTION

This account includes the investment in overhead and underground distribution line transformers used in transforming electric energy to secondary voltages. Equipment continues to be classified in this account regardless of whether actually in service or held in reserve for future use. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	33-R1	33-S1.5
Future NS Rate	-20.0%	-47.0%
Realized NS	-46.9%	
Average Age (yrs.)	12.5	
Derived Additions	$4,034,390,510	
Plant Retirements	$525,751,213	
Percent Retired	15.0%	
Plant Balance	$3,508,639,297	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Distribution transformers are replaced when they fail in service or when deterioration is observed during inspection or other field work. Deterioration includes leaks, corrosion and damage caused by vehicles or acts of nature. The statistical service life analysis for this account is stable and indicates average service lives in the mid–20s to high–30s and lower modal dispersions for bands with lower censoring and conformance indexes. It should be noted, however, that "cradle–to–grave" accounting is used for line transformers and associated equipment (*e.g.*, capacitors and network protectors). Service lives indicated from a statistical analysis provide estimates of the age at which transformers are permanently retired from service.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	Investment %	Full Band PLife-Curve
Undeground Transformers	1,262,937,734	36	34-S2
Overhead Transformers	1,045,618,106	30	40-S2
Fuseholders	749,306,101	21	38-S3
Non-unitized	57,769,013	2	
Other	393,008,343	11	25-O2
Total	3,508,639,297	100	36

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives between 25 and 40 years with lower modal dispersions and a dollar–weighted mean of 36 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

Life Estimation

Service–life indications from both the full account and subpopulation polynomial analyses bound the currently approved 33–S1.5 projection life–curve. Adjusting the currently approved parameters would imply a degree of precision beyond that which can be measured or estimated from a statistical life analysis.

Based on these considerations, retention of a 33–S1.5 projection–life is recommended for this account.

Net Salvage Analysis

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –46.9 percent realized from $525.8M of retirement activity constituting 13.0 percent of derived addition over the period 2002–2015. Most recent 5–year rolling bands show negative net salvage rates exceeding –130 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –27 and –47 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

Net Salvage Estimation

Based on the above analysis, a future net salvage rate of −47 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 369.00 – SERVICES

DESCRIPTION

This account includes the installed cost of overhead and underground services used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R1.5	45-R1.5
Future NS Rate	-100.0%	-387.0%
Realized NS	-271.0%	
Average Age (yrs.)	17.2	
Derived Additions	$1,347,309,968	
Plant Retirements	$45,902,562	
Percent Retired	3.5%	
Plant Balance	$1,301,407,406	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Overhead (OH) services are typically installed in older urban areas and remote rural areas where it is cost prohibitive to install conductor underground. Services are installed underground (UG) in newer urban areas and in new rural areas under development. Forces of retirement acting upon UG services are comparable to those acting upon UG primary conductors such as operating temperature, insulation type, vintage of cables, installation method, manufacturing quality, corrosive environment and where installed.

The statistical service life analysis for this account is based on highly censored (63-79 percent) samples producing unreliable service–life indications for a majority of trials. The analysis reveals a few inconclusive indications with service lives between the low–40s and mid–60s.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
UG Service Conductor	783,834,596	60	71-S2	85.4
OH Service Conductor	387,892,896	30	52-R1.5	70.6
Risers	63,694,659	5	64-R2	77.8
Non-Unitized	21,112,757	2		
Other	44,872,497	3	79-R2	82.1
Total	1,301,407,406	100	65	

Equipment classified in the "Other" category includes primarily underground conduit.

An analysis of the subpopulations indicates full–band average service lives between 52 and 79 years with lower modal dispersions and a dollar–weighted mean of 65 years. Subpopulation service life indications are similarly based on highly censored trials and the resulting indications are considered less than conclusive.

LIFE ESTIMATION

Neither the full account nor the subpopulation analysis provides sufficient evidence to warrant adjusting the currently approved 45–R1.5 projection life and curve. It was also revealed in conducting the analysis of this account that the pricing and vintaging of retirements may be contributing to the observed high degrees of censoring. Pending further investigation of the ageing of retirements, Foster Associates concurs with SCE that current parameters should be retained for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –271.0 percent realized from $45.4M of retirement activity constituting 3.4 percent of derived addition over the period 2002–2015. The most recent three 5–year rolling bands show negative net salvage rates exceeding –500 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –178 and –387 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions..

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −387 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 370.00 – METERS

DESCRIPTION

This account includes the cost of smart meters, devices and related appurtenances for use in measuring the electricity delivered to its users, whether actually in service or held in reserve. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	20-R3	20-R3
Future NS Rate	-5.0%	0.0%
Realized NS	-2.4%	
Average Age (yrs.)	7.7	
Derived Additions	$896,271,606	
Plant Retirements	$1,349,434	
Percent Retired	0.2%	
Plant Balance	$894,922,172	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

SCE has a population of slightly over 5 million installed meters. With the exception of a small number (less than 20 thousand) of electromechanical meters, AMI meters have been deployed systemwide. A large–scale migration to AMI meters began in 2009 following a pilot program in 2007–2008. The relatively recent deployment of AMI meters produces an insufficient sample of retirements to draw inferences from a statistical analysis. Censoring is about 99 percent.

LIFE ESTIMATION

AMI meters are electronic devices encased in plastic, typically installed in harsh environments, exposed to extreme weather conditions, and targets for vandalism. While the metrology element used in smart meters is generally considered mature and reliable technology, the life–span of the communication element is far from certain. Metering communication technology and protocols overlaid on electronic meters are rapidly evolving and will likely accelerate the rate of smart meter replacements relative to older–style, electromechanical metering equipment.

Lacking life analysis indications, the service life estimation for this account is based on a consideration of design life (20 years) and the opinions of Company engineers and operations personnel familiar with smart meters and ever evolving communications technology. Foster Associates therefore deferred to SCE in recommending retention of the currently approved 20–R3 projection life–curve for this account.

Net Salvage Analysis

The adjusted historical net salvage analysis for this account is based upon a minimal amount of $1.3M retired between 2011 and 2015 from derived additions exceeding $896M. The analysis indicates an overall net salvage rate of –271.0 percent realized from $45.4M of retirement activity constituting 3.4 percent of derived addition over the period 2002–2015. The most recent three 5–year rolling bands indicate negative net salvage rates exceeding –500 percent. The historical net salvage recorded in this account is not considered to be a reasonable predictor of future net salvage for AMI meters.

Net Salvage Estimation

Noting that "cradle–to–grave" accounting is used for meters and associated equipment (*e.g.*, current and potential transformers), minimal salvage and cost of disposal are expected for this account. Meter removal and reinstallation costs are charged to expense. Based on these observations and expectations, a zero percent future net salvage rate is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 373.00 – STREET LIGHTING AND SIGNAL SYSTEMS

DESCRIPTION

This account includes the installed cost of equipment used wholly for public overhead street and highway lighting. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	40-L0.5	48-L1
Future NS Rate	-30.0%	-100.0%
Realized NS	-111.3%	
Average Age (yrs.)	15.5	
Derived Additions	$974,350,403	
Plant Retirements	$102,266,782	
Percent Retired	11.7%	
Plant Balance	$872,083,621	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

During the last 15 years, SCE undertook an accelerated steel pole replacement program to address structural integrity deterioration and related public safety concerns. Pole deterioration found during this program was attributable to atmospheric and water corrosion, and pole, nut and anchor bolt rust. The majority of retired poles were replaced with concrete poles.

The Company conducts annual compliance patrolling and visual inspection of systems and facilities to identify safety issues early. The potential service life of concrete poles is enhanced by adding chlorine ion intrusion inhibitors and using high quality attachments with galvanized coatings.

The major forces of retirement for street light poles include car accidents, deterioration, idled facilities, and street upgrades and relocations.

The statistical service life analysis for this account is reasonably stable for trials with lower censoring, conformance indexes, and non–negative fitted hazard functions. Indications from such trials support average service lives between the lower 40s and mid–50s.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

An analysis of the subpopulations indicates full–band average service lives between 27 and 67 years with lower modal dispersions and a dollar–weighted mean of 54 years. Service–life indications derived from a statistical analysis of the

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Poles	388,111,928	46	58-S0.5	48.9
Cable & Conduit	260,964,203	31	67-R2	66.3
Light Fixtures	177,270,403	21	27-S0	2.4
Non-unitized	22,542,405	3		
Other	23,194,681	3	39-O2	38.3
Total	872,083,621	100	54	

Table 2. Major Structural Components

combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on these considerations and observations, a 48–L1 projection life–curve, derived from the full account broadest placement and observation bands, is considered reasonable and is recommended for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –111.3 percent realized from $102,266,782 of retirement activity constituting 10.5 percent of derived addition over the period 2002–2015. The most recent 5 and 10–year rolling bands indicate net salvage rates exceeding –115 percent.

NET SALVAGE ESTIMATION

Based on these observations and the historical net salvage analysis, retention of the currently approved –100 percent future net salvage rate is recommended for consideration by SCE. It appears unlikely that lesser amounts of cost of removal will be realized in the future.

General Plant Depreciable
Account: 390.00 – Structures and Improvements

Description

This account includes the cost in place of structures and improvements used for Company purposes, the cost of which is not properly includible in other structures and improvements accounts. Account statistics and current and proposed parameters are shown in Table 1 and the composition of major structural components classified in this account at December 31, 2015 is shown in Table 2.

	Current	Proposed
Plife-Curve	38-R3	45-R0.5
Future NS Rate	-5.0%	-10.0%
Realized NS	-24.5%	
Average Age (yrs.)	12.7	
Derived Additions	$1,035,908,700	
Plant Retirements	$88,821,443	
Percent Retired	9.4%	
Plant Balance	$947,087,257	

Table 1. Account Parameters and Statistics

Category	Investment Amount ($)	%
Common	229,531,472	24
Buildings	220,785,582	23
Power & Lighting Systems	170,306,642	18
HVAC	100,134,622	11
Alarms and Monitoring Systems	65,852,228	7
Foundations & Related Structures	57,908,077	6
Water Supply Systems	33,133,484	3
Non-unitized	27,376,214	3
Miscellaneous	42,058,937	4
	947,087,257	100

Table 2. Structural Components Distribution

Life Analysis

The statistical service life analysis for this account indicates average service lives between 40 and 60 years for trials with lower censoring and conformance indexes. A number of trials are considered less reliable if hazard rates are unrealistically declining or zeroed to avoid the suggestion of negative hazard rates. No attempt was made to analyze equipment classified in the subpopulations for this plant category.

LIFE ESTIMATION

Based on the indications obtained from the broader bands of the statistical life analysis, a 45–R0.5 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The historical net salvage analysis for this account indicates an overall adjusted net salvage rate of –24.1 percent realized from $88.8M of retirement activity constituting 8.6 percent of derived addition over the 2002–2015 study period.

NET SALVAGE ESTIMATION

Based on these observations and the expectation of continuing negative net salvage, a –10 percent future net salvage rate is recommended for consideration by SCE. This recommendation adjusts the future net salvage parameter from a –5 percent in the direction of the historical net salvage observations.

Appendix B

Formulation of Per Unit Net Salvage Rates

FORMULATION OF PER-UNIT NET SALVAGE RATES

Average realized net salvage per unit retired for the k[th] subpopulation of a plant account is given by

$$\overline{NSR_k} = \frac{\sum_{2009}^{2015} NSR_{jk}}{\sum_{2009}^{2015} NUR_{jk}}$$

where

NSR_j = net salvage realized in the j^{th} activity year; and
NUR_j = number of units retired in the j^{th} activity year.

The installed cost per unit of plant remaining in service at December 31, 2015 from the i^{th} vintage of the k[th] subpopulation of a plant account is given by

$$ICU_{ik} = \frac{PIS_{ik}}{NUS_{ik}}$$

where

PIS_{ik} = plant in service from the i^{th} vintage of the k^{th} subpopulation; and
NUS_{ik} = number of units in service from the i^{th} vintage of the k^{th} subpopulation.

The ratio of the net salvage per unit retired to the installed cost of the i^{th} vintage of the k[th] subpopulation of a plant account becomes

$$PUR_{ik} = \frac{\overline{NSR_k}}{ICU_{ik}}.$$

The plant–weighted average of vintage subpopulation ratios used to estimate the future net salvage of vintages at the account level (*i.e.*, the sum of subpopulation vintages) is given by

$$\overline{PUR_i} = \frac{\sum_{k=1}^{n} \left(PIS_{ik}\right)\left(PUR_{ik}\right)}{\sum_{k=1}^{n} PIS_{ik}}$$

where

n = number of subpopulations within a plant account.

Forecasted retirements from the i^{th} vintage in the j[th] activity year are the product of plant in service at December 31, 2015 and the probability of retirement in activity years beyond 2015 obtained from an Iowa–type probability density function. Retirements from the i^{th} vintage in the jth activity year are given by

$$RET_{ij} = \left(PIS_i\right)\left(p_{ij}\right)$$

where

p_{ij} = probability of retirement during age interval j–i–0.5 and j–i+0.5.

Estimated future net salvage for retirements from the i^{th} vintage in the jth activity year is given by

$$FNS_{ij} = RET_{ij}\left(\overline{PUR_i}\right)\left(1+r\right)^{j-2015}$$

r = estimated rate of inflation.

where

The estimated future net salvage rate for a plant account is the ratio of the sum of future net salvage to the sum of vintaged plant in service given by

$$FNS = \frac{\sum_i \sum_j FNS_{ij}}{\sum_i \sum_k PIS_{ik}}.$$

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
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PREPARED DIRECT TESTIMONY OF JACOB W. MOON

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-9)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	)))	**Dkt. No. ER19-______-000**

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
JACOB W. MOON

(EXHIBIT SCE-9)

Mr. Moon sponsors three main portions of Southern California Edison Company's ("SCE") proposed Formula Rate and associated Formula Rate Protocols: 1) separation of existing transmission and distribution facilities under the Operational Control of the California Independent System Operator Corporation ("CAISO" or "ISO") from SCE's non-ISO controlled facilities (see following Sections II and III); 2) forecast ISO direct capital expenditures that will translate into forecast plant additions and forecast Construction Work-In-Progress ("CWIP") used in the proposed Formula Rate (*see* Sections IV, V, and VI); and 3) determination of the portion of operation and maintenance ("O&M") expense booked as transmission that is associated with ISO transmission facilities (*see* Section VII). In Sections II and III, Mr. Moon discusses: 1) the methodology used in the proposed Formula Rate to identify and separate SCE's transmission and distribution ("T&D") facilities under the operational control of the CAISO from SCE's non-ISO facilities as reflected in Schedule 7 (*see* Section II); and 2) the determination of High Voltage and Low Voltage gross plant percentages as reflected in Schedule 31 (*see* Section III). In Section IV, he also sponsors forecast direct capital expenditures that will contribute to plant additions to rate base and the Federal Energy Regulatory Commission-approved CWIP in rate base through December 2019 as reflected in Schedules 10 and 16. In Section V, Mr. Moon provides the general overview, current status, expected activities, and associated major cost components for these plant additions and CWIP in rate base. He also describes SCE's CWIP tracking procedure and exclusions. In Section VI, Mr. Moon also briefly describes Statement BM – Construction Program Statement showing that the projects for which CWIP in rate base treatment is sought are part of a prudent, least-cost energy supply program that includes consideration of alternatives. Lastly, in Section VII, Mr. Moon explains how SCE's proposed Formula Rate determines the O&M expenses for T&D accounts as reflected in Schedule 19. He also discusses how the proposed Formula Rate assigns T&D O&M expenses to ISO and non-ISO functions as reflected in Schedules 19 and 27.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

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Southern California Edison Company	)	**Dkt. No. ER19-______-000**
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**PREPARED DIRECT TESTIMONY OF
JACOB W. MOON
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY**

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

A. My name is Jacob W. Moon, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Senior Advisor of Financial Analysis in the Operational Finance department within the Finance organizational unit. My primary responsibilities include managing the preparation of financial materials from the Transmission and Distribution ("T&D") organizational unit associated with SCE's filings before the Federal Energy Regulatory Commission ("FERC" or "Commission") and the California Public Utilities Commission ("CPUC").

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Science degree in Mathematics and Applied Science with an emphasis in Actuarial Science from the University of California, Los Angeles and a Master of Business Administration degree from the A. Gary Anderson Graduate School of Management at the University of California, Riverside.

I joined SCE in 2000 as a Professional Aide. I was promoted to Financial Analyst in 2002 and Senior Financial Analyst in 2005. In 2007, I transferred to Edison International (parent holding company of SCE). In 2011, I returned to SCE as a Senior Finance Project Manager and assumed my current position.

Q. Have you submitted testimony to the Commission previously?

A. Yes, I have submitted testimony in three of SCE's requests to recover abandoned plant costs in Dockets ER12-239, ER14-1857, and ER16-1025 and also in SCE's transmission formula rate proceeding in Docket ER18-169.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the methodology used in the proposed Formula Rate to identify and separate SCE's T&D facilities under the Operational Control of the ISO from SCE's non-ISO facilities as reflected in Schedule 7 of Exhibit SCE-4 (Section II), and to describe the methodology used to split SCE's ISO T&D facilities into High Voltage ("HV") and Low Voltage ("LV") categories, as reflected in Schedule 31 of Exhibit SCE-4 (Section III). In addition, I provide SCE's transmission capital expenditures forecast for the period January 1, 2017 through December 31, 2019 (Section IV). This forecast is an input used in determining the Incremental Forecast Period Transmission Revenue Requirement ("TRR"). Also, I describe SCE's CWIP expenditure tracking procedure and exclusions (Section V) and Statement BM (Section VI). Finally, in Section VII, I explain how SCE's proposed Formula Rate determines the O&M expense component of the Prior Year TRR. I also explain how the proposed Formula Rate assigns recorded

O&M expenses to SCE facilities under the Operational Control of the CAISO. The methodology is briefly described in Section 10 of SCE's Protocols for the proposed Formula Rate, and it is discussed more fully by Mr. Allstun (Exhibit SCE-10).

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 7 (Plant Study), the majority of Schedule 19 (O&M) (except for the allocators sponsored by Mr. Allstun on Lines 48-85, Column 5), the portion of Schedule 27 (Allocators) relating to the calculation of the O&M allocators (Lines 24-48), and Schedule 31 (HV/LV).

II. SEPARATION OF EXISTING T&D FACILITIES INTO ISO AND NON-ISO FACILITIES

Q. How does SCE separate its T&D facilities plant into ISO and non-ISO for ratemaking?

A. Pursuant to Section 9 of the proposed Formula Rate Protocols, SCE performs a "Plant Study" which separates SCE's investment in T&D plant into ISO and non-ISO.

Q. What is the Plant Study?

A. The Plant Study is a study that SCE performs in order to separate its T&D plant into ISO and non-ISO categories. The Plant Study analyzes SCE's existing facilities and determines which facilities are under the ISO's Operational Control. In the proposed Formula Rate, plant classified as Transmission under the Commission's Uniform System of Accounts that is under the ISO's Operational Control is called "Transmission Plant – ISO", while Distribution Plant under the ISO's Operational Control is called "Distribution Plant – ISO". As discussed below in Section III, the Plant Study further subdivides Transmission Plant – ISO and Distribution Plant – ISO into HV and LV categories. As of the time of this testimony, SCE has no distribution facilities under the Operational Control of the ISO, but Distribution Plant – ISO is still kept in the proposed Formula Rate as a placeholder.

Q. Is the use of the Plant Study in setting SCE's transmission rates a new concept?

A. No. SCE has been performing the Plant Study since the establishment of the ISO in 1998. Further, the results of the Plant Study have been used in SCE's FERC rate cases since the establishment of the ISO. The Plant Study used in conjunction with this filing was performed in the first quarter of 2018.

Q. Why does SCE perform this study?

A. SCE performs the Plant study because its accounting records do not directly identify the portion of SCE's T&D plant that is under the Operational Control of the ISO and this separation is needed for both FERC and CPUC ratemaking purposes. Generally, SCE records investment in T&D facilities to the corresponding FERC plant account with locational identifiers. For substation facilities, the locational identifier typically refers to a specific substation location. For transmission lines, the locational identifier may refer to a specific line, group of lines, or voltage. Some of these facilities are easily classified as network facilities that are 100% ISO, or radial facilities that are 100% non-ISO. Other facilities, like shared-use locations for transmission lines and substations with both ISO and non-ISO facilities, and dual use facilities that support ISO and non-ISO functions, such as substation fencing, buildings, and grounding grid, need to be classified as ISO and non-ISO on an allocation basis. As such, Section 9 of SCE's proposed Protocols provides for SCE to perform an annual Plant Study in order to separate ISO from non-ISO plant, using the methodology set forth below.

Q. How is SCE's Plant Study reflected in the Formula Rate?

A. The results of the Plant Study are summarized on an account-by-account basis in Schedule 7 of the proposed Formula Rate (Exhibit SCE-4). These values form the basis for plant in service as identified in Schedule 6 described in Mr. Gunn's testimony, Exhibit SCE-7, and the derivation of HV and LV Gross Plant Percentages identified in Schedule 31 of Exhibit SCE-4, described in Section III below.

Q. Please describe the methodology used in the proposed Protocols for separating T&D plant into ISO and non-ISO.

A. The proposed Protocols first address the separation of T&D plant recorded to Accounts 350-359, and 360-362 (Section 9(b) of the proposed Protocols). Each asset location within these accounts is placed into one of the following five categories:

1. All ISO: Facilities for which all assets at the location are under the Operational Control of the ISO.
2. Non-ISO: Facilities for which all assets at the location are not under the Operational Control of the ISO.
3. Mixed ISO and Non-ISO Substation: Substation facilities that have a mixture of plant under ISO Operational Control and not under ISO Operational Control. These assets are individually examined to determine which are under the ISO control and which are not. Assets under ISO Operational Control are classified as ISO, while assets not under ISO Operational Control are classified as non-ISO. Assets performing a dual use function (both ISO and non-ISO) are allocated based on the percentages of ISO/non-ISO assets at the asset location.

4. Mixed ISO and Non-ISO Lines: Transmission lines that have a mixture of plant under ISO Operational Control and not under the Operational Control of the ISO. These assets are allocated using the transmission line classification method, discussed below.
5. Other: Substation facilities that do not fall into one of the above first three categories in a location are classified as ISO or Non-ISO in proportion to the total percentage of Transmission Plant – ISO or Distribution Plant – ISO determined in above categories (1) through (3).

Q. Please describe the transmission line classification method referred to above.

A. Transmission line classification is addressed in Section 9(c) of the proposed Protocols. Transmission lines that have a mixture of assets under the ISO's Operational Control and not under the ISO's Operational Control are allocated on a line-mile basis. For example, if in a particular location 8 miles of a 10-mile transmission line are under ISO Operational Control and 2 miles are not, 80 percent of the cost of the line will be classified as ISO and 20 percent as non-ISO. Using line miles is a reasonable method for dividing the costs of these mixed-use assets as it allocates costs in proportion to ISO and non-ISO facilities for the asset under consideration.

Q. Will SCE make the Plant Study available to its customers for their review in each Annual Update process?

A. Yes. The proposed Protocols provide for SCE to provide a summary of Plant Study for the Prior Year in its annual Draft Annual Update posting. This summary appears as Schedule 7 in the Formula Rate (Exhibit SCE-4). In addition, the proposed Protocols provide that a copy of the complete Plant Study for the Prior Year will be included in the workpapers. In this filing, SCE is including a copy of the Plant Study for the Prior Year of 2017 in its workpapers, Exhibit SCE-29.

Q. How much recorded T&D plant does SCE attribute to ISO?

A. As shown on Schedule 7, of Exhibit SCE-4, SCE attributes $8,573,445,553 of transmission plant (Line 21, Column 2) and $0 of distribution plant (Line 30, Column 2) to ISO for the Prior Year.

III. CALCULATION OF HV AND LV PERCENTAGES

Q. How does SCE calculate HV / LV split of ISO plant?

A. SCE divides ISO Transmission plant into HV and LV categories based on the methodology set forth in Section 12 of Rate Schedule 3 to Appendix F of the ISO Tariff, and thereby calculates the HV and LV percentages that are included in Schedule 31 of the proposed Formula Rate, Exhibit SCE-4.

Q. Please describe Schedule 31.

A. Schedule 31 of Exhibit SCE-4 contains information and calculations used in determining the HV and LV percentages of total ISO Gross Plant. SCE, in accordance with the ISO Tariff, defines a HV Facility as having an operating voltage of 200 kV or higher, while an LV Facility is one having an operating voltage of less than 200 kV. The ISO Tariff also provides direction in Appendix F, Schedule 3, Section 12 on how a Participating Transmission Owner ("PTO") such as SCE should determine HV and LV Gross Plant percentages. Schedule 31 of Exhibit SCE-4 implements the direction provided in the ISO Tariff.

In Schedule 31, all Transmission Plant – ISO and Distribution Plant – ISO from the Plant Study is classified into one of five categories: 1) HV Transmission Lines; 2) LV Transmission Lines; 3) HV Substations; 4) Straddle Substations; and 5) LV Substations. Gross Plant for categories 1 and 3 is classified as all HV, while Gross Plant for categories 2 and 5 is classified as all LV. Straddle Substations have operating voltages both above and below 200 kV, and as such contain both HV and LV Gross Plant. Gross Plant for "Straddle Substations" is specifically examined to determine the operating voltage of components within the facility. The Gross Plant within the Straddle Substations that operates as HV is identified as HV Gross Plant, while the Gross Plant that operates as LV is identified as LV Gross Plant. The only plant that operates at both HV and LV are "HV/LV Transformers." The Gross Plant associated with these HV/LV Transformers is attributed to HV and LV in proportion to the HV/LV percentages of all other ISO Gross Plant. SCE also classifies forecast capital additions and incentive project CWIP as either HV or LV based on the HV/LV percentages of ISO Gross Plant.

Q. What percentage of SCE ISO plant is considered High Voltage?

A. As shown on Schedule 31 of Exhibit SCE-4, Line 37, 96.998% of recorded and forecast plant is identified as HV and 3.002% as LV.

IV. CAPITAL EXPENDITURE FORECAST

Q. What capital expenditures are included in the proposed Formula Rate?

A. The proposed Formula Rate includes SCE's ISO capital expenditure forecast for the period January 1, 2018 through December 31, 2019. These expenditures translate into forecast plant additions and/or forecast CWIP used in proposed Formula Rate Schedules 10 for Forecast Period Incremental CWIP by Project and Schedule 16 for Forecast Plant Additions for In-Service ISO Transmission Plant located in Exhibit SCE-4.

Q. Please describe what you mean by "capital expenditures".

A. Capital expenditures as used in my testimony represent direct T&D capital expenditures such as labor, materials, contract, other, and allocated T&D

organizational unit division overhead costs. Capital expenditures as used in this context do not include capitalized corporate overheads added in the plant additions process as described by Mr. Gunn in Exhibit SCE-7.

Q. What are the components of the forecast direct capital expenditures that you are sponsoring?

A. I am sponsoring two categories of direct capital expenditures – the expenditures associated with incentive and non-incentive ISO transmission facilities that are projected to be either added to rate base or placed in service during the period January 2018 through December 2019.

Q. Please provide a description of the non-incentive ISO transmission facilities that are included in your capital forecast.

A. The non-incentive ISO transmission facilities represent those facilities that will be under the Operational Control of the CAISO, but have not been afforded any project-specific incentives by the Commission. The non-incentive ISO transmission facilities are further broken down as Blanket Specifics or Specific Project work orders.

Blanket Specifics work orders represent capital expenditures for routine work with no specific planned in-service date that can be grouped together from an operational and accounting perspective. Examples include transformer and pole replacements. Without a specific planned in-service date, capital expenditures forecast in January will close to plant in the same time period. Specific Project work orders represent unique capital expenditure activities that are carried out as individual projects with a planned in-service date. The in-service date shown in the workpapers is used to estimate the month and year when the total accumulated construction costs will close to plant or rate base. Exhibit SCE-29 (WP Schedule 16 – Summary of ISO Cap Expenditures Non-

Inc Projects, "Total Non-Incentive Transmission Projects" line) displays the Blanket Specifics and the Specific non-incentive project work orders that I am sponsoring. In total, those non-incentive work orders represent $550 million in ISO transmission projects forecast to be placed in service during the period January 2018 through December 2019.

Q. Please provide a description of the incentive ISO transmission facilities that are included in your capital forecast

A. Incentive projects include facilities that will be under ISO Operational Control for which SCE has received Commission approval of a project-specific incentive such as 100% of CWIP in rate base prior to being placed in service, or incentive return on equity ("ROE") adders. SCE has received approval to include 100% of CWIP in rate base for eight projects that affect the forecast: 1) Tehachapi Renewable Transmission Project ("TRTP" or "Tehachapi); 2) Colorado River Substation Expansion ("CRS Expansion"); 3) Whirlwind Substation Expansion ("Whirlwind Expansion"); 4) Calcite Substation (formerly Jasper, part of South of Kramer Transmission Project) ("Calcite"); 5) West of Devers Transmission Project ("West of Devers"); 6) Alberhill System ("Alberhill"); 7) Eldorado-Lugo-Mohave Upgrade ("ELM"); and 8) Mesa Substation ("Mesa"). In total, these eight incentive projects represent approximately $666 million in CWIP expenditures forecast to be under construction during the period January 2018 through December 2019, Exhibit SCE-29, (Workpaper to Schedule 10 Forecast CWIP Capital Expenditures by PIN and Activity). A portion of the facilities associated with these incentive projects will be placed in-service during this period as discussed later in my testimony. Once placed in service, the CWIP expenditures will be excluded from CWIP in rate base. SCE's CWIP capital expenditures forecast is summarized in workpapers, Exhibit SCE-29.

Q. Please generally describe the Capital Expenditure Forecasting process.

A. All estimated capital additions are derived from the construction costs already spent and included in CWIP at prior year-end and forecast capital expenditures for the Incremental Forecast Period. The forecast capital expenditures are included in SCE's annual corporate-wide capital expenditure forecast process that occurs in the second half of the year and culminates in an approved five-year capital budget and forecast, typically in the first quarter of the following year. This approved capital budget and forecast is what is referred to as the SCE's "5-Year Capital Budget and Forecast ("Capital Plan")." The Capital Plan includes a forecast of all transmission and distribution facilities (both ISO-related and non-ISO). Through this process, SCE reviews the expected capital expenditures and schedules for projects included in the forecast. In preparation for this proposed Formula Rate filing, SCE may update some of the assumptions in the Capital Plan to reflect known changes.

Q. Please summarize the capital forecast included in your testimony.

A. As discussed in my testimony, (and as noted in Exhibit SCE-29's WP Schedule 10&16 - Identification of ISO Projects above $5M) during the period January 2018 through December 2019, SCE forecasts:

- $550 million in ISO non-incentive network transmission closings (including $318 million in ISO Blanket Specifics closings),
- $666 million in FERC incentive rate qualified CWIP expenditures, and;
- $89 million of CWIP Expenditures closing to plant (including $7 million of TRTP plant closings that have a ROE adder of 125 basis points (as noted in Schedule 14, Line 200 of Exhibit SCE-4)).

Q. How are the expenditures forecasts you are sponsoring utilized in the Formula Rate?

A. As explained in Exhibit SCE-7, Mr. Gunn utilizes the forecast expenditures to develop final amounts of additions to Forecast Net Plant Additions and Incremental CWIP to be included in the Forecast Period.

Q. Please provide a summary of the major transmission projects that SCE forecasts will be placed in service during the period January 2018 through December 2019.

A. As shown in my workpapers (WP Schedule 10 & 16 Identification of ISO Projects above $5M) included in Exhibit SCE-29, in addition to the numerous but relatively small transmission projects, there are 20 significant transmission projects (each $5 million or greater in ISO-related costs) that are expected to be placed in service in the period January 2018 through December 2019 – six Blanket Specifics, eleven Specific non-incentive projects, and three Specific incentive projects. These projects will increase the reliability of the ISO transmission grid, increase access to new generation resources to serve the ISO market, and/or provide congestion relief. The costs associated with these facilities are included in the Formula Rate proposed by SCE in this filing. SCE's proposed Formula Protocols, Section 3(a) specifies that SCE will provide workpapers detailing specific information regarding its capital forecast.

V. CWIP PROJECT EXPENDITURE TRACKING PROCEDURE AND EXCLUSIONS

Q. What are the forecast direct capital expenditures, by project, for the Incentive Projects that have received Commission approval for including 100% of CWIP in rate base?

A. Table 1 below provides a summary of forecast FERC-jurisdictional direct capital expenditures for Projects that have received Commission approval for, including CWIP in rate base. A monthly and detailed forecast of direct capital expenditures for these Projects is provided in the workpapers, Exhibit SCE-29.

Table 1

Forecast FERC CWIP Direct Capital Expenditures *(Nominal $Millions)*			Source of Primary Authorization		
Project	**2018**	**2019**	**Utility**	**CAISO**	**CPUC**
Tehachapi	6.475	0	-	x	CPCN
CRS Expansion	0.003	0	-	x	PTC
Whirlwind Expansion	0.023	0	-	x	Exempt
Calcite	0.200	1.595	-	x	Subject to PTC Requirements
West of Devers	104.028	153.139	-	x	CPCN
Alberhill	1.313	8.660	-	x	CPCN (pending)
ELM	19.432	46.944	-	x	CPCN (pending)
Mesa	69.798	84.750	-	x	PTC
Total	**$201.272**	**$295.088**			

Q. Please describe the process by which SCE tracks expenditures associated with the Projects.

A. Project expenditures are tracked at a summary level through unique Project designation in the SAP work management system. A Work Breakdown Structure ("WBS") is used to organize project information for work management and reporting purposes. Within each Project, unique work order numbers are established to track specific project elements. Work orders are designed to track costs over the full spectrum of activities necessary to develop and complete a project. The costs recorded to the Projects and work orders are monitored by Project Controls Engineers who use contracts, purchase orders and/or work authorizations to make sure the charges are valid for a particular work order.

Q. How does SCE ensure that the costs recorded and forecast for the Projects reflect only those facilities that, when completed, will be under the operational control of the CAISO?

A. All project costs are identified in the work orders by the jurisdiction through which they are recoverable (*i.e.*, FERC or CPUC). SCE creates unique FERC subaccount numbers for FERC-jurisdictional assets that are under the operational control of the CAISO. In addition, SCE creates different CPUC subaccount numbers for CPUC-jurisdictional assets.

Q. How does SCE ensure that costs for other transmission projects are not reflected in the CWIP associated with the Projects?

A. SCE uses specific work orders associated with the Projects identified in this filing to record and forecast CWIP expenditures.

Q. Have you excluded any Project costs from the CWIP forecast?

A. Yes. SCE has excluded telecommunications costs associated with the Projects, which are recorded in separate work orders. SCE has also excluded any CPUC-jurisdictional transmission and distribution costs associated with the Projects and costs not related to new construction (*i.e.*, removal and relocation costs for the new facilities).

Q. Please describe the detailed historic information that you included in this filing.

A. Detailed information on the nature of the construction expenditures SCE incurred for the period beginning January 1, 2017 through December 31, 2017 is provided in the workpapers to Schedule 10 – Recorded CWIP Expenditures

2017. The information is provided in a similar level of detail that SCE submitted in Docket Nos. ER10-160, ER11-1952, ER11-3697 and ER18-169.

VI. STATEMENT BM

Q. Please describe briefly Statement BM.

A. Statement BM of the Commission's regulations requires utilities seeking recovery of CWIP in rate base to provide a statement showing that the projects for which CWIP treatment is sought are part of a prudent, least-cost energy supply program that includes consideration of alternatives. Statement BM discusses SCE's transmission infrastructure expansion and describes how each of the Projects have undergone a rigorous and independent evaluation process before being approved by the CAISO and the CPUC. Such evaluations considered, among other things, the need for the Projects, the cost-effectiveness, and project alternatives. SCE is including a Statement BM with this filing.

VII. THE O&M EXPENSE FORMULA

Q. Please explain how the Formula Rate calculates total T&D O&M expense.

A. Total T&D O&M expense is calculated in Schedule 19, Part 1 of the proposed Formula Rate, Exhibit SCE-4. The starting point for calculating T&D O&M expense is SCE's annual recorded information reported in FERC Form 1 as shown in Schedule 19, Part 1, Column 2. In SCE's books and records, Transmission O&M expense is presented in Accounts 560-573 and Distribution O&M expense is presented in Accounts 580-598. Currently, only Transmission O&M expense is reflected in the proposed Formula Rate, and there is zero Distribution O&M expense.

Schedule 19 then separates the total FERC Form 1 O&M expense into certain sub-accounts as appropriate, then into labor and non-labor components using internal financial reports. The resultant labor amount net of NOIC ("Non-Officer Incentive Compensation") is consistent with the true labor reported in FERC Form 1 Page 354 (Distribution of Salaries and Wages).

Next, the formula makes adjustments to the recorded O&M (Schedule 19, Part 1, Columns 7 and 8) to remove expenses that are recovered through other FERC-authorized rate mechanisms. These adjustments include the Reliability Services Balancing Account ("RSBA"), Transmission Access Charge Balancing Account ("TACBA"), and the Transmission Revenue Balancing Account ("TRBA") shown on Line 15. These adjustments also include the expenses that are recovered through CPUC authorized rate mechanisms, including the Energy Resource Recovery Account ("ERRA") shown on Lines 4 and 12 ("Scheduling, System Control and Dispatch Services" and "Wheeling Costs") and the Mojave Balancing Account ("MBA") shown on Line 7 ("MOGS Station Expense"), and any shareholder expenses shown on Lines 14, 26, and 39 ("Miscellaneous Transmission Expenses – Allocated," "Maintenance of Overhead Lines – Allocated," and "Accounts with no ISO Distribution Costs," respectively), if applicable.

Lastly, the formula adds in the Transmission NOIC and Distribution NOIC on Lines 32 and 40, respectively, which is paid out to T&D employees as further discussed in the testimony of Mr. Mindess (Exhibit SCE-12). These NOIC costs are appropriately included as part of functionalized O&M expense in Schedule 19 of Exhibit SCE-4.

The above adjustments result in "Adjusted Recorded O&M Expenses" which are shown in Schedule 19, Part 1, Line 43, Columns 9-11 of Exhibit SCE-4.

Q. Part 1 of Schedule 19 contains multiple lines for many accounts. Why is Schedule 19 presented in this manner?

A. This is necessary in order to calculate the adjustments discussed above and in order to determine how much of the recorded T&D O&M expenses are ISO-related. To accomplish this, the Formula Rate separates the FERC Form 1 O&M accounts into various components that further define the activities associated with the expenses recorded in each particular FERC Account. For example, the expenses recorded in Account 560, Operation Supervision and Engineering, are reported on Form 1 as one line item. However, some of the expenses recorded to this account relate to payments made to the Los Angeles Department of Water and Power ("LADWP") for Sylmar and Salt Water Project ("SRP") for Palo Verde O&M expenses related to shared ownership of ISO-controlled transmission facilities. These expenses are purely ISO-related, while other expenses in this account are not. The Formula Rate identifies payments to LADWP and SRP separately for purposes of allocating costs between ISO and non-ISO O&M expense (which is performed in Schedule 19, Part 2) as noted in Exhibit SCE-4.

Q. How does the Formula Rate determine the portion of the total Transmission and Distribution O&M expense (calculated in Schedule 19, Part 1) that is attributable to facilities under the Operational Control of the ISO ("ISO O&M Expense")?

A. The portion of Total T&D O&M expense that is attributable to facilities under the Operational Control of the ISO is calculated in Schedule 19, Part 2 of Exhibit SCE-4. ISO O&M Expense is composed of expenses that are: 1) directly assignable to ISO and non-ISO facilities and activities; or 2) developed based on appropriate metrics that can be used to allocate the expenses between

ISO and non-ISO facilities and activities. For further discussion and reasonableness of SCE's proposed O&M allocation, please see Mr. Allstun's testimony (Exhibit SCE-10).

Q. Does this conclude your testimony?

A. Yes, it does.

DECLARATION

I, Jacob W. Moon, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 8, 2019 in Rosemead, California

Jacob W. Moon

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-_____-000**
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PREPARED DIRECT TESTIMONY OF DANIEL J. ALLSTUN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-10)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
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SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
DANIEL J. ALLSTUN

(EXHIBIT SCE-10)

Mr. Allstun describes the proposed allocation methodology for Operation and Maintenance ("O&M") expenses reflected in SCE's proposed Formula Rate. Mr. Allstun explains the six allocators that SCE uses to assign O&M expenses to ISO Transmission on Schedule 19 within the proposed Formula Rate and provides justification for the reasonableness of SCE's proposal. Mr. Allstun also describes the calculation of the allocators reflected on Schedule 27 of the proposed Formula Rate.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
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PREPARED DIRECT TESTIMONY OF
DANIEL J. ALLSTUN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Daniel J. Allstun, and my business address is 8631 Rush St., Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am the Manager of FERC Contract and Cost Analysis in the FERC Rates and Market Integration Division of the Regulatory Affairs Department. My primary responsibilities include providing analysis and policy guidance supporting the development of pricing and related rate terms associated with contracts and services subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC" or "Commission"), as well as management of the implementation of SCE's formula transmission rate.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science Degree in Mechanical Engineering from California State University at Fullerton in May 1984. I joined SCE as an Engineer Trainee in the Nuclear Engineering, Safety and Licensing

Department in January 1983. In July 1984, I was promoted to the position of Licensing Engineer, working on licensing issues involving San Onofre Nuclear Generating Station, Unit 1. In January 1989, I transferred to the Regulatory Policy and Affairs Department as a Regulatory Cost Analyst. During my tenure with the Regulatory Policy and Affairs Department, my responsibilities have involved a host of regulatory issues including the restructuring of the natural gas industry, the restructuring of the electric industry, and cost and policy analysis of various gas and electric issues. From 1994 through 2005, my primary responsibility was analysis of SCE's FERC-jurisdictional contracts and policies. Since 2006, my primary responsibility has focused on directing cost of service analysis, rate recovery, and involvement in various rate-related proceedings at FERC.

Q. Have you submitted testimony to the Commission previously?

A. Yes, I sponsored testimony in Docket Nos. ER18-169, ER17-250, ER16-1025, ER14-1857, ER12-239, ER11-1952, ER10-160, ER09-1534, ER09-187, ER08-1343, ER08-375, ER06-186, EL04-137, ER03-549, ER02-2189, ER02-925, and ER98-441.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the six allocators that SCE uses for the allocation of transmission and distribution ("T&D") Operation and Maintenance ("O&M") expenses to SCE's cost of service for its T&D assets under the Operational Control of the California Independent System Operator ("ISO") on Schedule 19 within the proposed FERC Formula Rate (Exhibit No. SCE-4). These allocated O&M expenses are included in SCE's Transmission

Revenue Requirement ("TRR"). I also provide justification for the reasonableness of SCE's O&M allocation proposal and briefly describe the calculation of the allocators reflected on Schedule 27 of the proposed Formula Rate.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring the allocation factors used in Schedule 19 (O&M) which appear on Schedule 19 on Lines 48-87, Column 5.

II. OVERVIEW OF SCE'S PROPOSED O&M ALLOCATION

Q. Please explain how the proposed Formula Rate calculates total T&D O&M expense.

A. As discussed more fully by Mr. Moon (Exhibit No. SCE-9), the total adjusted T&D O&M expense is calculated in Schedule 19, part 1, of the proposed Formula Rate. Schedule 19, part 1, also separates the total FERC Form 1 T&D O&M expense into certain sub-accounts, as appropriate, and into labor and non-labor components using internal financial reports. Finally, the adjusted T&D O&M is attributed to ISO using various allocation factors performed in Schedule 19, part 2, of the proposed Formula Rate.

Q. What is the methodology used by the proposed Formula Rate to allocate the portion of the total T&D O&M expense attributable to facilities under the Operational Control of the ISO ("ISO O&M Expense") included in SCE's TRR?

A. The proposed Formula Rate O&M allocation methodology consists of two parts: 1) directly assignable expenses; or 2) allocated expenses based on metrics that are used to allocate the expenses between ISO and non-ISO.

The proposed Formula Rate O&M allocation methodology is identical to the methodology currently in place under SCE's Second Formula Rate.

III. REASONABLENESS OF ALLOCATION METHODOLOGY

Q. Do you believe the proposed Formula Rate allocation methodology for the O&M expense between ISO and non-ISO is reasonable?

A. Yes. As I noted, the proposed Formula Rate O&M allocation methodology is identical to the methodology currently in place under the Second Formula Rate. SCE's proposed Formula Rate O&M allocation methodology is a formulistic approach with the allocations based on easily verifiable facts (circuit breakers, line miles, etc.). As a result, the allocation methodology is transparent, readily subject to external verification by the Commission and the stakeholders, and easily replicated by third parties when compared to the Original Formula Rate.

Below, I will first explain the methodology that SCE uses to determine how costs will be allocated to transmission rates. This allocation methodology, generally speaking, relies on direct cost assignment, line miles, and circuit breaker counts. I will then explain which category of costs is covered by each of the allocation principles noted above. I would like to first explain the asset allocators that SCE will use in more detail.

Q. What allocators is SCE proposing to use?

A. SCE is proposing to use direct assignment (100% ISO or 100% non-ISO), ISO line miles (overhead and underground), and ISO circuit breaker counts for purposes of O&M cost allocation.

Q. Can you please explain direct assignment?

A. Direct assignment is the most accurate way to allocate costs. SCE uses direct assignment where possible based on the nature of the expenses and accounting system limitations such as when expenses are related 100% to ISO and can be readily identified in its accounting system. This includes expenses that are directly related to ISO activities or facilities such as expenses associated with Palo Verde and Sylmar substations. Similarly, direct assignment is used for expenses where the activity or facility is clearly non-ISO such as WAPA line transmission fees.

Q. Why does SCE not use the direct assignment allocation methodology for all its assets?

A. For many expenses, it is simply not possible to directly assign to ISO or non-ISO due to the nature of the underlying O&M activity, which supports both ISO and non-ISO facilities. Therefore, an appropriate allocation methodology must be chosen.

Q. Please explain the four asset-driven allocators.

A. In choosing a reasonable allocation methodology, SCE considered methodologies used by other utilities in formula rates, the value of transparency, replicability by third parties and the Commission, and the principles of cost causation. SCE believes that the resulting allocation methodology is just and reasonable, as well readily understandable and implementable. SCE's proposed Formula Rate uses four distinct asset-driven metrics. As shown in Table 1, these metrics have been relatively stable over the 2012 – 2017 period.

Table 1 Line Miles and Circuit Breaker Count						
Allocator	2012	2013	2014	2015	2016	2017
Transmission Overhead Line Miles	48.9%	46.0%	47.2%	46.5%	46.7%	46.8%
Transmission Underground Line Miles	1.7%	0.4%	0.3%	0.3%	1.4%	1.4%
Transmission Circuit Breakers	34.4%	34.8%	34.8%	36.0%	36.3%	36.6%
Distribution Circuit Breakers	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%

1. <u>Costs Allocated on the Basis of Overhead and Underground Transmission Line Miles</u>

The proposed Formula Rate uses transmission line miles to allocate the O&M costs directly related to transmission lines between ISO and Non-ISO recorded in FERC Accounts 563, 564, 567, 571, and 572. These accounts reflect the costs associated with operating and maintaining the overhead and underground transmission lines. As such, the costs in these accounts were allocated based on the overhead or underground transmission line miles. SCE believes that the allocation of the O&M expenses included in these accounts based on line miles is reasonable since it is the needs of SCE's overhead and underground transmission lines, along with the structures supporting the lines, that drive the work required to support and maintain such lines, to maintain the integrity and reliability of the system and require SCE to incur the associated O&M costs. As shown in Schedule 27, Lines 27 and 29, SCE attributes 5,683 of 12,156 (or 46.8% of total) overhead line miles and 5 of 360 (or 1.4% of total), Lines 33 and 35, underground line miles to ISO for the Prior Year. The Percent ISO Allocation Factor for overhead line miles has been relatively stable for past few years and there is no expectation of a change in this trend.

2. <u>Costs Allocated on the Basis of Transmission and Distribution Circuit Breakers Numbers</u>

The proposed Formula Rate uses circuit breaker count as an overall allocator to separate O&M costs that are neither directly assigned or allocated on line miles. In particular, FERC Accounts, 560, 561, 562, 566, 568, 569, 570, 573, 582, 590, 591, and 592 record the costs that are allocated on the basis of circuit breaker counts as shown in Schedule 19. Schedule 27 reflects the fact that SCE attributes 1,205 of 3,288 (or 36.6% of total) transmission circuit breakers, Lines 39 and 41, and 0 of 8,853 (or 0% of total) distribution circuit breakers, Lines 45 and 47, to ISO for the Prior Year. SCE believes that the allocation of the non-directly assignable and non-line related Transmission and Distribution O&M expenses based on circuit breaker count is reasonable since SCE's circuit breaker count is a reasonable proxy for the transmission and distribution facilities under the Operational Control of the ISO and the O&M expenses incurred to support those facilities. Typically, major transmission and distribution system components such as lines, transformers, capacitor banks, etc. have circuit breakers at points of interconnection into substations. The primary function of circuit breakers is to automatically isolate problems on the electric system before they can cascade into a complete system outage. Circuit breakers perform the critical function of turning off the flow of electricity to a circuit which has encountered a problem and interrupt the flow of electricity in transmission or distribution lines. Additionally, circuit breakers are used to isolate facilities for maintenance activities. I would also note that the Percent ISO Allocation Factor for transmission circuit breakers has been relatively stable for past few years and there is no expectation of a change in this trend.

Q. What are the results of the application of the T&D O&M cost allocation methodology of Schedule 19 of SCE proposed Formula Rate?

A. SCE proposed Formula Rate uses recorded O&M expenses as input to Schedule 19 as shown on Exhibit No. SCE-4. When the proposed Formula Rate is populated with recorded 2017 information, the cost allocation methodology attributes $77.53 million in O&M expenses to ISO, Schedule 19, Line 91, Column 6.

IV. DIRECTLY ASSIGNABLE EXPENSES

Q. Please describe the directly assigned transmission O&M expenses attributable to ISO Transmission.

A. There are six major categories of transmission O&M expenses that are directly assigned by the proposed Formula Rate. Within these 6 major categories, there are 12 sub-accounts the costs of which are assigned 100% to ISO O&M. There are also five sub-accounts that record costs entirely excluded from allocation to the ISO (0% to ISO). The directly assigned transmission O&M costs appear in Accounts 560, 561.4, 561.5, 562, 565, 566, 567, 568, 569, 570, 571, and 572. SCE's proposed methodology for directly assignable expenses is identical to SCE's Second Formula Rate.

Q. Please describe the major categories of O&M expenses that are directly assigned to ISO O&M by the proposed Formula Rate?

A. There are four major categories of transmission O&M expenses directly assigned (100%) to ISO O&M. These four categories are as follows:

Sylmar/Palo Verde (FERC Accounts 560, 562, 566, 567, 568, 569, 570, 571, and 572): SCE makes payments to Los Angeles Department of Water & Power ("LADWP") and Salt River Project ("SRP") for O&M expenses related to the shared ownership of several high voltage transmission facilities where SCE has turned over its share to ISO's Operational Control. LADWP is the operating agent for the Celilo-Sylmar 1000kV DC transmission line terminating at Bonneville Power Administration's Celilo Converter Station near the border of Oregon and Washington, along with the Sylmar Converter Station located in Southern California. SRP is the operating agent for the Palo Verde Nuclear Generating Station switchyard located in central Arizona. These recorded O&M expenses are directly assigned to ISO O&M Expenses (Lines 49, 55, 63, 66, 68, 70, 72, 74, and 76 of Schedule 19).

Reliability, Planning, and Standards Development (FERC Account 561.500): This category includes the cost of SCE's Reliability Planning and Standards Development Group, which is responsible for transmission facility performance and expansion planning. This includes developing transmission performance and reliability criteria, performing transmission reliability assessments, studying load and generation interconnections, conducting post-disturbance reviews of major events, and coordination with the WECC. These recorded O&M expenses are directly assigned to ISO O&M Expenses (Line 52 of Schedule 19).

Transmission of Electricity by Others (FERC Account 565): This account includes amounts payable to others for the transmission rights over transmission facilities owned by others where SCE has placed such rights under the Operational Control of the ISO. Therefore, the expenses are directly assigned to ISO O&M Expenses. In recorded 2017, SCE recorded expenses associated with payment from Arizona Public Service ("APS") for the Four Corners to Eldorado 500kV line. This agreement, however, was terminated in 2016. Consequently, SCE anticipates the expenses in this account to be $0 in 2018 and beyond at this time (Line 58 of Schedule 19).

Eldorado (FERC Account 567): SCE pays rent to the BLM for its Eldorado-Mead No. 1 & 2 220 kV line and the Mohave-Eldorado 500 kV line. Since these lines are under the CAISO's operational control, these recorded O&M expenses are directly assigned to ISO O&M Expenses (Line 65 of Schedule 19).

Q. Please describe those transmission expenses that are excluded from ISO O&M.

A. There are two major categories of transmission O&M expenses excluded from ISO O&M (0% to ISO). These categories are:

WAPA Agreement (FERC Account 565): SCE has a transmission service agreement with the Western Area Power Administration ("WAPA") for remote service utilizing non-ISO facilities and the expenses are directly assigned to non-ISO O&M expenses. This transmission service is used to for distribution service to SCE's retail load in the vicinity of Parker California (Line 60 of Schedule 19).

Miscellaneous (FERC Accounts 561.400, 562, 565, 566): These accounts are either related to SCE's energy procurement for retail customers or are recovered through other rate mechanisms. These sub-accounts are all assigned 0% to the ISO (Lines 51, 54, 59, and 62 of Schedule 19).

Q. Are there distribution O&M accounts that directly assigned to ISO O&M?

A. No. Currently, there are no distribution related O&M accounts attributed to ISO (Columns 6 through 8, Line 88 of Schedule 19).

III. ALLOCATED EXPENSES BASED ON APPROPRIATE METRICS

Q. You indicated earlier that certain O&M expenses were allocated between ISO and non-ISO using metric-based allocators. Please describe the metric-based allocation of O&M expenses.

A. For certain FERC T&D O&M accounts, the proposed Formula Rate utilizes four distinct asset-driven metrics to determine how to appropriately allocate O&M expenses between ISO and non-ISO. These allocators are: 1) number of ISO overhead transmission line miles as a percent of total ISO and non-ISO overhead transmission line miles; 2) number of ISO underground transmission line miles as a percent of total ISO and non-ISO underground transmission line miles; 3) number of ISO transmission circuit breakers as a percent of total ISO and non-ISO transmission circuit breakers; and 4) number of ISO distribution circuit breakers as a percent of total ISO and non-ISO distribution circuit breakers. As indicated above, this is consistent with the Second Formula Rate.

Q. What accounts are allocated using metric-based allocators?

A. Accounts 560, 561, 562, 563, 564, 566, 567, 568, 569, 570, 571, 572, and 573 use a metric-based allocator for those expenses not directly assigned. I will explain the allocation for each account in turn.

Q. Please describe the allocation of expenses in Account 560 – Operations Supervision and Engineering – Allocated.

A. This activity records the expenses of operations engineering, supervision of switching centers, and departmental overheads relating to management, supervision, and clerical support. Expenses include the engineering support for the operation of the transmission system in addition to the general supervision for SCE's manned switching centers.

The expenses recorded in this activity support all of the transmission functions and the proposed Formula Rate allocates these expenses based upon the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 48 of Schedule 19).

Q. Please describe the allocation of expenses in Account 561 – Load Dispatch – Allocated.

A. These accounts record expenses incurred in load dispatching operations pertaining to the transmission of electricity. Activities charged to these accounts include the directing of switching, emergency operations, curtailment of interruptible loads, load shedding, outage planning for maintenance activities, monitoring of equipment performance, and equipment control. Load dispatching activities are separated into two groups – one involving switching and the other involving system voltage control.

The expenses recorded in this activity support all of the transmission functions and the proposed Formula Rate allocates these accounts between ISO and non-ISO based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 50 of Schedule 19).

Q. Please describe the allocation of expenses in Account 562 – Station Expenses – Allocated.

A. This activity records the work performed by the Power Delivery Switching Centers to operate the electric system. This activity captures the operational costs of transmission substations and switching centers. Substation operator activities include field switching, processing line and equipment outages, and responding to interruptions of transmission circuits. This activity also records expenses relating to test crew activities in the routine testing and inspection of relays and protection schemes. The proposed Formula Rate allocates this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 53 of Schedule 19).

Q. Please describe the allocation of expenses in Account 563 – Overhead Line Expenses – Allocated.

A. This account records patrolmen's activities in operating field switches, patrolling overhead lines, inspecting, and if required, making the necessary repairs to overhead transmission lines. As such, the proposed Formula Rate allocates this account based on the number of ISO overhead line miles as a percentage of total transmission overhead line miles (Line 56 of Schedule 19).

Q. Please describe the allocation of expenses in FERC Account 564 – Underground Lines Expenses – Allocated.

A. This account records expenses for routine patrolling, inspecting, testing of terminations, and clearing of underground transmission lines. As such, the proposed Formula Rate allocates this account based on the number of ISO underground line miles as a percentage of total transmission underground line miles(Line 57 of Schedule 19) .

Q. Please describe the allocation of expenses in Account 566 – Miscellaneous Transmission Expenses – Allocated.

A. This activity records expenses related to safety programs and training, miscellaneous transmission expenses such as records and mapping costs, and miscellaneous expenses from other departments such as SCE's Operations Support for maintaining transmission and substation buildings and grounds. In addition, this activity records the costs of employees supporting growth in renewable energy and energy supply for customers throughout SCE’s service territory. Activities include negotiating and developing new contracts for interconnection, transmission, or distribution service for both generation and load projects. Activities also include oversight of the grid interconnection process (for both transmission and distribution services) from receipt of an application through signature of an interconnection or transmission agreement. Lastly, this activity records the cost of employees who administer and manage transmission, distribution and interconnection contracts or agreements after they are signed by SCE and customers. This group scans documents into a contract management system, establishes actions to be taken based on contract provisions, processes financial and tariff obligations, resolves audit and contract dispute issues, and monitors compliance with new regulations. The proposed Formula Rate allocates this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 61 of Schedule 19).

Q. Please describe the allocation of expenses in Account 567 – Line Rents – Allocated.

A. This activity records rents paid by SCE for use of transmission line rights-of-ways on property owned by others. This activity also records expenses associated with the Morongo lease payment. This lease results from SCE's six existing transmission lines that currently cross tribal lands. The proposed Formula Rate allocates this account based on the number of ISO overhead line miles as a percentage of total transmission overhead line miles (Line 64 of Schedule 19).

Q. Please describe the allocation of expenses in Account 568 – Maintenance Supervision and Engineering – Allocated.

A. This activity records expenses for substation maintenance supervision, engineering and supervision by personnel from other departments, and overheads associated with management, supervision and clerical support. The proposed Formula Rate allocates this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 67 of Schedule 19).

Q. Please describe the allocation of expenses in Account 569 – Maintenance of Structures – Allocated.

A. This activity records expenses for the maintenance of transmission substation structures including the maintenance of heating and air conditioning systems, plumbing, lighting, and landscaping of substation structures. These costs support both substation operations and maintenance activities. This account also records the expenses incurred in: 1) the maintenance of computer hardware supporting the transmission function; 2) ongoing support for software products serving the transmission function; and 3) the maintenance of communication equipment supporting the transmission function. The proposed Formula Rate allocates this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 69 of Schedule 19).

Q. Please describe the allocation of expenses reflected in Account 570 – Maintenance of Station Equipment – Allocated.

A. This activity includes the costs associated with: 1) rebuilding and testing of transformers, replacement of deteriorated oil in transformers, and the material and labor to rebuild transformer bushings; 2) diagnostic tests and replacement or refurbishment of major components of circuit breakers; 3) maintaining and repairing transmission shunt reactors, series capacitors, condensers, and regulators; 4) maintenance of transmission substation equipment-circuit breaker, transformer, and voltage control equipment-performed by the nuclear, steam, and hydro organizations for the T&D organization; and 5) general substation maintenance to replace trench covers and other common substation facilities.

This account also records O&M expenses related to capital construction. When capital work is performed at substations to replace equipment, upgrade the infrastructure, or add new equipment to an existing facility, expenses are often incurred that are directly driven by the capital work, but do not meet capitalization criteria. Examples of capital-related O&M expenses include repairing or strengthening structures to support the additional or replaced unit, relocation of equipment (like a capacitor bank) to make space for new additions to an existing facility, switch-rack reconfiguration, and secondary wiring.

Since the maintenance recording in this activity is general in nature, it is reasonable for the proposed Formula Rate to allocate this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 71 of Schedule 19).

Q. Please describe the allocation of expenses in Account 571 – Maintenance of Overhead Lines – Allocated.

A. This activity records expenses for: 1) repairing and painting transmission line towers, poles and fixtures; 2) repairing and relocating transmission line apparatus, cleaning and washing transmission insulators, and repairing transmission line conductors; and 3) clearing rights-of-way, grading transmission line roads and trails, and trimming and removing trees along transmission lines. This activity also records O&M expenses related to capital construction. When capital work is performed to replace equipment, upgrade infrastructure or add new equipment, expenses are often incurred related to the capital work, but do not meet capitalization criteria. Examples of capital-related O&M expenses include: paving the ground when new equipment is installed, repairing or strengthening structures to support the additional or replaced unit, or relocation of equipment to make space for new additions.

Since the expenses recorded in this account support overhead transmission lines, it is reasonable for the proposed Formula Rate to allocate this account using total ISO-controlled transmission overhead line miles as a percent of total overhead transmission line miles (Line 73 of Schedule 19).

Q. Please describe the allocation of expenses in Account 572 – Maintenance of Underground Lines – Allocated.

A. This activity records expenses for cleaning and repairing of underground vaults, switch repairs and adjustments, and repair of cable splices. Since the expenses recorded in this account support underground transmission lines, it is reasonable for the proposed Formula Rate to allocate this account using total ISO-controlled transmission underground line miles as a percent of total underground transmission line miles (Line 75 of Schedule 19).

Q. Please describe the allocation of expenses in Account 573 – Maintenance of Miscellaneous Transmission Plant – Allocated.

A. This account records expenses for repairing or replacing equipment damaged by adverse wind, heat, rain, lightning, earthquake, fire, and other like activities. Since the maintenance recorded in this activity is general in nature, it is reasonable for the proposed Formula Rate to allocate this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 77 of Schedule 19).

Q. Please describe the allocation of expenses in Account 582 – Station Expenses.

A. This activity includes expenses of station operation, changing voltage settings of regulators, and maintaining station logs and records. This activity also records expenses for the testing and inspection of relays and protection schemes and routing testing and inspection of distribution substation equipment. The proposed Formula Rate allocates these expenses using the ISO-controlled distribution circuit breaker count as a percent of total distribution circuit breakers. Substation testing and inspecting activities are in support of distribution equipment, so it is reasonable to use the ISO distribution circuit breaker count as an allocator for this activity (Line 82 of Schedule 19). Currently there are no ISO-controlled distribution circuit breakers and consequently the allocation is zero.

Q. Please describe the allocation of expenses in Account 590 – Maintenance Supervision & Engineering.

A. This account includes expenses incurred in the supervision of required maintenance work on the distribution system. The proposed Formula Rate allocates this account based on the ISO-controlled distribution circuit breaker count as a percent of total distribution circuit breakers. Supervision of substation maintenance is in support of distribution equipment, so it is reasonable to use the ISO distribution circuit breaker count as an allocator for this activity (Line 83 of Schedule 19). Currently there are no ISO-controlled distribution circuit breakers and consequently the allocation is zero.

Q. Please describe the allocation of expenses in Account 591 – Maintenance of Structures.

A. Account 591 records expenses for the maintenance of distribution substation structures including the maintenance of heating and air conditioning systems, plumbing, lighting, and landscaping of substation structures. This account supports substation O&M activities. The proposed Formula Rate allocates this account based on the ISO-controlled distribution circuit breaker count as a percent of total distribution circuit breakers. Maintenance of substation structures is in support of distribution equipment, so it is reasonable to use the ISO distribution circuit breaker count as an allocator for this activity (Line 84 of Schedule 19). Currently there are no ISO-controlled distribution circuit breakers and consequently the allocation is zero.

Q. Please describe the allocation of expenses in Account 592 – Maintenance of Station Equipment.

A. This activity includes the expenses associated with: 1) rebuilding and testing of transformers, replacement of deteriorated oil in transformers, and the material and labor to rebuild transformer bushings; 2) diagnostic tests and replacement or refurbishment of major components of circuit breakers; 3) maintenance and repair of transmission shunt reactors, series capacitors, condensers, and regulators; and 4) maintenance performed by the Hydro organization for the T&D organization. The activities include circuit breaker, transformer and voltage control equipment maintenance. This account also includes general substation maintenance to replace trench covers and other common substation facilities.

Since the maintenance recording in this activity is general in nature, it is reasonable for the Formula Rate to allocate expenses based on the ISO-controlled distribution circuit breaker count as a percent of total distribution circuit breakers (Line 85 of Schedule 19). Currently there is no ISO-controlled distribution circuit breakers and consequently the allocation is zero.

Q. Are there any additional expenses that are allocated between ISO O&M and non-ISO?

A. Yes, Schedule 19 also allocates Non-Officer Incentive Compensation ("NOIC") between ISO T&D and non-ISO. As discussed in the testimony of Mr. Mindess (Exhibit No. SCE-12), SCE records all incentive compensation in Administrative and General Expenses. The proposed Formula Rate splits total

T&D NOIC expenses into Transmission and Distribution based on recorded labor expenses Transmission, or Distribution, divided by total T&D labor expenses. Next, the proposed Formula Rate allocates the transmission portion of NOIC expenses between ISO and non-ISO based on the total ISO transmission labor as a percent of total transmission labor. The ISO allocation of Distribution NOIC expenses is zero in the proposed Formula Rate.

Q. Does this complete your testimony?

A. Yes.

DECLARATION

I, Daniel J. Allstun, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 5, 2019 in Rosemead, California

Daniel J. Allstun

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
ALFRED L. LOPEZ

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-11)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)))**	**Dkt. No. ER19-______-000**

SUMMARY OF THE PREPARED DIRECT TESTIMONY OF ALFRED L. LOPEZ

(EXHIBIT SCE-11)

Mr. Lopez's testimony provides the explanation of the Income Tax Formula used in this Formula Rate proceeding to calculate Income Tax Expense included in the Prior Year Transmission Revenue Requirement ("TRR") and True Up Adjustment, and the tax expense imbedded in Incremental Forecast Period TRR. Mr. Lopez also provides detailed descriptions of the components of the Income Tax Formula used in these transmission revenue requirements. In addition, Mr. Lopez provides the explanation of the methodology for determining Accumulated Deferred Income Tax ("ADIT") balances and Net Excess Deferred Income Tax balances included in the adjustment to FERC Rate Base. Finally, Mr. Lopez describes the components of taxes other than income ("Other Taxes") reflected in the Prior Year TRR and True Up Adjustment.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)**	**Dkt. No.**	**ER19-______-000**

PREPARED DIRECT TESTIMONY OF ALFRED L. LOPEZ ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Alfred L. Lopez, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefy describe your present responsibilities at Southern California Edison Company ("SCE").

A. I am a Senior Advisor, Tax Research & Planning at SCE. My responsibilities include managing tax-related regulatory matters that come before the Federal Energy Regulatory Commission ("FERC" or the "Commission") and the California Public Utilities Commission ("CPUC") for SCE, as well as other tax-related research and planning activities.

Q. Briefly describe your educational and professional background.

A. I hold a Master of Science in Taxation from Golden Gate University, and a Bachelor of Science Degree in Business Administration (with an emphasis in Accounting) from California State University, Los Angeles. I am a member of the California Society of CPAs and the American Institute of Certified Public Accountants, and have been employed by SCE in the Tax Department since

1989. Over the years, I have been responsible for Tax Research and Planning, Accounting for Income Taxes, and Regulatory Tax-related Matters. Prior to joining SCE, I worked in the tax and audit groups of a public accounting firm and the tax departments of two other large corporations.

Q. Have you previously submitted testimony to the Commission?

A. Yes. I have submitted testimony in SCE's transmission rate case proceedings Docket No. ER09-1534, Docket No. ER11-3697 and Docket No. ER18-169.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of the first portion of my testimony is to provide the explanation of the Income Tax Formula used in this Formula Rate proceeding to calculate Income Tax Expense included in the Formula Rate, as well as to provide a detailed description of the components of the Income Tax Formula. The purpose of the second portion of my testimony is to provide the explanation of the Accumulated Deferred Income Tax balance and Net Excess Deferred Income Tax balance reflected in Schedule 9 that are used in the adjustment to the FERC Rate Base amount reflected in Schedules 1 and 4 of the Formula Rate. The final portion of my testimony describes the components of taxes other than income reflected in Schedule 1 of the Prior Year TRR and Schedule 4 of the True Up Adjustment.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring the Other Taxes and Income Taxes portion of Schedule 1 (Lines 19-36 and 57-65), as well as Schedule 9 (ADIT), Schedule 25 with respect to the following three components of the Wholesale Difference - Taxes Deferred –

Make Up Adjustment, Excess Deferred Taxes, and Taxes Deferred ACRS/MACRS, Lines 33-35, and Schedule 26 (Tax Rates).

Q. Does the Formula Rate Spreadsheet in this proceeding reflect the necessary changes to properly reflect the tax-related ratemaking implications resulting from Public Law 115-97?

A. Yes. As described in more detail in each of the following Sections, the Formula Rate Spreadsheet reflects the necessary changes to properly reflect the tax-related ratemaking implications resulting from Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA") that was enacted on December 22, 2017.

In summary, for purposes of the Income Tax Formula in Line 65 of Schedule 1 (Base TRR), Line 60 (Amortization of Excess Deferred Tax Liability) of Schedule 1 will also include the amortization of the Net Excess Deferred Tax Liability as a result of the TCJA beginning in Prior Year 2018, when amortization actually begins to be recorded. In addition, the Income Tax Formula used for purposes of calculating Prior Year TRR will reflect the income tax rates applicable to the Rate Year (*i.e.*, 2019) in lieu of the Prior Year (*i.e.*, 2017).

For purposes of ADIT, Schedule 9 will include ADIT balances in FERC Accounts 190, 282 and 283 that reflect the Federal income tax rate of 21% as a result of the TCJA. In addition, the unamortized Net Excess Deferred Income Tax Liability balance as a result of the TCJA will be included in Schedule 9 to reduce Rate Base.

Each of these items described herein are pursuant to and consistent with the Commission's Order Accepting Tariff Revisions, Subject to Condition, effective November 16, 2018,[1] which was issued in response to SCE's request,[2] made pursuant to Section 205(d) of the Federal Power Act, to revise its Transmission Owner Tariff as a result of the TCJA.[3]

II. INCOME TAX FORMULA

Q. Please explain the purpose of the Income Tax Formula used to calculate Income Tax Expense amounts reflected in Schedules 1 and 4, and embedded in Schedule 2.

A. The purpose of the Income Tax Formula is to provide a formulaic mechanism consistent with the Formula Rate ratemaking approach that reflects the appropriate level of recovery of Income Tax Expense associated with SCE's transmission revenue requirement. The Income Tax Formula is included in both the Prior Year TRR and the True Up TRR, and is embedded in the Annual Fixed Charge Rate and Annual Fixed Charge Rate for CWIP reflected in the Incremental Forecast Period TRR. The Income Tax Formula reflects the combined impact of Federal and state income tax expense associated with SCE's transmission revenue requirement, and the adjustments to Income Tax Expense for Tax Credits and Other.

Q. Please provide a description of the Income Tax Formula.

A. The Income Tax Formula is as follows:

Income Tax Expense = [((RB * ER) + D) * (CTR/(1 – CTR))] + CO/(1 – CTR)

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[1] *S. Cal. Edison Co.*, 166 FERC ¶ 61,006 (2019).

[2] *S. Cal. Edison Co.*, Docket No. ER18-2440, Revisions to Transmission Formula Rate (filed Sept. 17, 2018).

[3] In addition, Schedule 9 now includes the description in Line 4 and Notes 4 and 5 pursuant to *S. Cal. Edison Co.*, 166 FERC ¶ 61,006 (2019), as well as revised descriptions in lines 1, 7, 10, 12 and 15 to provide additional clarity. These additional notes and descriptive changes do not affect any of the calculations..

Where:

RB = Rate Base

ER = Equity Rate of Return that includes Common and Preferred Stock

D = Book Depreciation of AFUDC-Equity Book Basis

CTR = Composite Tax Rate

CO = Tax Credits and Other

The Income Tax Expense, as calculated pursuant to the Income Tax Formula, represents the combination of the following components: 1) the Federal and state income tax expense associated with SCE's recovery of equity rate of return on Rate Base, grossed-up to a revenue requirement; 2) the Federal and state income tax expense on the recovery of book depreciation associated with AFUDC-Equity book basis, grossed-up to a revenue requirement; and 3) Tax Credits and Other tax adjustments to income tax expense, grossed-up to a revenue requirement.

For the first component of the Income Tax Formula, Rate Base is multiplied by the equity rate of return percentage, with the resulting product multiplied by the tax gross-up factor to derive the required revenue for this tax component. The purpose of this first component is to reflect the recovery of income taxes associated with the profit component of the equity rate of return on Rate Base. The tax gross-up factor is equal to the Composite Tax Rate divided by one minus the Composite Rate. The Composite Tax Rate is equal to the Federal statutory income tax rate plus the product of the state income tax rate times one minus the Federal statutory income tax rate. The Federal income tax rate is reflected in Line 1 of Schedule 26. The state income tax rate is reflected in Line 8 of Schedule 26. The Composite Tax Rate is reflected in Line 59 of Schedule 1.

For the second component of the Income Tax Formula, the recovery of book depreciation associated with the capitalized AFUDC-Equity amount included in book basis is multiplied by the tax gross-up factor to derive the revenue requirement for this tax component. The purpose of this second component is to reflect the recovery of income taxes associated with the profit component of the equity rate of return on previous construction work in progress balances. The recovery of this tax gross-up is necessary because capitalized AFUDC-Equity amounts included in book basis and subsequently recovered through book depreciation expense is a ratemaking construct that has no equivalent for tax purposes. Thus, when revenue is received for book depreciation associated with the AFUDC-Equity basis, there is no offsetting tax basis to depreciate for tax purposes, which results in additional taxable income and additional income tax expense that must be recovered in rates.

For the third component of the Income Tax Formula, Tax Credits and Other adjustments to tax are divided by one minus the Composite Tax Rate to derive the appropriate grossed-up revenue requirement for this tax component.

Q. Please provide a description of the Tax Credits and Other Items.

A. Tax Credits and Other tax adjustments included in the Income Tax Formula reflected in Schedule 1 and Schedule 4 consist of the following three items: 1) Amortization of Net Excess Deferred Income Tax Liability; 2) Amortization of the Investment Tax Credit; and 3) Amortization of the South Georgia Income Tax Adjustment. The amortization amounts for each of these three items are reflected in Lines 60 through 62 of Schedule 1, and Line 25 of Schedule 4.

Q. Please explain the Amortization of Net Excess Deferred Tax Liability.

A. As briefly explained in Section I of this testimony, the Amortization of Net Excess Deferred Income Tax Liability, as reflected in Line 60 of Schedule 1, represents the adjustment to income tax expense resulting from legislative changes to statutory corporate income tax rates. Section 13001(a) of the TCJA reduced the Federal corporate statutory income tax rate to 21% effective January 1, 2018. The reduced income tax rate resulted in net excess deferred tax amounts eligible to be returned to ratepayers under the average rate assumption method ("ARAM") as required under the tax normalization rules of Section 13001(d) of the TCJA. The ARAM amortization will be reflected beginning in Prior Year 2018, when ARAM will actually begin being recorded. ARAM will reduce income tax expense for ratemaking purposes over the remaining related book life beginning in the year the annual book depreciation exceeds tax depreciation. In addition, adjustment to income tax expense resulting from the previous legislative change in corporate income tax rates will continue to include the fixed annual amount of $200 for retail customers over a period that will end after the year 2024. The net of these two amortization amounts, *i.e.*, ARAM and $200, will be reflected in Line 60 of Schedule 1.

For wholesale customers, the ARAM amortization will also begin in Prior Year 2018 for the Net Excess Deferred Income Taxes resulting from the TCJA over the remaining book life, along with the continued fixed annual net Amortization of Excess Deferred Tax Liability of $42,900 adjustment to retail amortization rates of $43,100 as reflected in Line 21 of Schedule 25 over a period that will end after the year 2024.

Q. Please explain the Amortization of Investment Tax Credit

A. The Amortization of Investment Tax Credit for retail and wholesale customers of $520,000, as reflected in Line 61 of Schedule 1, represents the reduction of income tax expense for the remaining deferred investment tax credit balance being amortized over the book life of the related property as required by Internal Revenue Code Section 46(f)(2) prior to its repeal. Under the tax normalization rules, the fixed annual amount of $520,000 associated with the amortization of investment tax credit will end after the year 2018. For Prior Year 2019, the Amortization of Investment Tax Credit will be $183,000, and then will be zero thereafter.

Q. Please explain the Amortization of the South Georgia Income Tax Adjustment

A. The Amortization of the South Georgia Income Tax Adjustment represents the recovery of tax benefits previously flowed through to customers in prior regulatory proceedings.

For retail customers, the fixed annual South Georgia Income Tax Adjustment of $2,606,000, as reflected in Line 62 of Schedule 1, represents the recovery of income tax benefits previously flowed-through to retail customers prior to the regulatory transistion of retail transmission revenue requirement proceedings from the CPUC jurisdiction to FERC jurisdiction in March 1998. Under prior CPUC jurisdiction, retail customers were provided with flow-through tax accounting treatment for certain book/tax differences, such as state tax depreciation differences and Federal tax depreciation differences on pre-1981 assets, that were subsequently required under FERC jurisdiction to be accorded full normalization tax accounting treatment. The South Georgia

Income Tax Adjustment is designed to recover those previously flowed-through tax benefits that would not otherwised be recovered under the fully normalized ratemaking tax accounting treatment. The fixed annual South Georgia Income Tax Adjustment of $2,606,000 is amortized over a 27-year period that will end after the year 2024.

For wholesale customers, the fixed annual South Georgia Income Tax Adjustment amortization amount of $103,000 represents SCE's recovery of income tax benefits previously flowed-through to wholesale customers prior to FERC's implementation to full normalization. The difference of $2,503,000 between wholesale and retail amortization of the South Georgia Income Tax Adjustment is reflected in Line 8 of Schedule 25. This fixed annual South Georgia Income Tax Adjustment is amortized over a 27-year period that will end after the year 2024.

Q. Please explain the ACRS/MACRS Deferred Tax Adjustment used in the Calculation of the Wholesale Differences to Base TRR

A. The ACRS/MACRS Deferred Tax Adjustment balance represents the differences in the retail and wholesale amounts of the ACRS/MACRS deferred tax adjustment balances resulting from the regulatory transition of retail transmission revenue requirement proceedings from the CPUC jurisdiction to FERC jurisdiction in March 1998, calculated on an average of BOY and EOY basis. This difference is shown on Line 10, Column 1 of Schedule 25, and the associated annual amortization adjustment is shown on Line 10, Column 2. This fixed annual ACRS/MACRS Deferred Tax Adjustment is amortized over a 27-year period that will end after the year 2024.

III. ACCUMULATED DEFERRED INCOME TAX

Q. What is Accumulated Deferred Income Tax?

A. Accumulated Deferred Income Tax represents the tax effect on the accumulated temporary difference between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable income or deduction amounts in future years when the reported amount of the asset is recovered or the liability is settled.

Q. What are the general implications of ADIT on Rate Base?

A. FERC-related ADIT balances are used to adjust Rate Base in the computations of Base TRR and the True Up Adjustment. If the tax basis of an asset is less than its amount reported in the financial statements or if the tax basis of a liability is greater than its amount reported in the financial statements, then the ADIT will have a liability (*i.e.*, credit) balance that will reduce Rate Base. If the tax basis of an asset is greater than its amount reported in the financial statements or if the tax basis of a liability is less than its amount reported in the financial statements, then the inverse will occur and the ADIT will have an asset (*i.e.*, debit) balance that will increase Rate Base.

Q. Does SCE's FERC Form 1 provide information on ADIT balances?

A. Yes. SCE's FERC Form 1 includes year-end ADIT balances in FERC accounts 190, 282 and 283 that are used in the Formula Rate proceedings to calculate the ADIT adjustment to Rate Base as reflected in Line 13 of Schedule 1 and Line 13 of Schedule 4. FERC Account 190 ADIT represent asset balances and are reflected on page 234 of the FERC Form 1. FERC Account 282 ADIT represent liability balances and are reflected on pages 274-275, and Account 283 represent liability balances and are reflected on pages 276-277 of the FERC Form 1.

Q. Do the ADIT balances reflect the changes from the TCJA?

A. Yes, beginning with 2017 ending balances, ADIT reflects the lower Federal income tax rate of 21%. The net difference between ADIT balances reflected with a Federal income tax rate of 21% and the ADIT balances reflected with a Federal income tax rate of 35% results in a Net Excess Deferred Income Tax Liability balance that will also be used to reduce Rate Base (*see* Section IV for further details of Net Excess Deferred Income Tax Liability).

Q. How does the Formula Rate determine the ADIT adjustment to Rate Base?

A. Schedule 9 of the Formula Rate separately examines each recorded ADIT subaccount balance of FERC Accounts 190, 282 and 283 to determine the amount attributable to ISO transmission and distribution that should be included in the ADIT adjustment to FERC Rate Base. In Schedule 9, each line-item ADIT subaccount 190, 282 and 283 balances are identified with costs that are either: (1) subject entirely to recovery from a regulatory jurisdiction or proceeding other than through this FERC Formula Rate proceeding, (2) subject entirely to recovery through this FERC Formula Rate proceeding, (3) shared costs that relate primarily to property, or (4) shared costs that relate primarily to labor.

ADIT subaccount balances that are identified with costs that are subject entirely to recovery from regulatory jurisdictions or proceedings other than this FERC Formula Rate proceeding are excluded entirely from any impact to the ADIT component of FERC Rate Base in this Formula Rate proceeding. ADIT subaccount balances that are identified with costs that are subject entirely to recovery in this FERC Formula Rate proceeding are included in their entirety in the ADIT component of FERC Rate Base. ADIT subaccount balances that are identified with costs that are shared costs that relate primarily to property are first reduced for the property-related allocated percentage attributable to non-electric operations (as reflected in Instruction 2 of Schedule 9) before the remaining balances are allocated to ADIT in the FERC Formula Rate based on the FERC-related Transmission Plant Allocation Factor percentage as reflected in Scheule 27, Line 22. ADIT subaccount balances that are identified with costs that are shared costs that relate primarily to labor are first reduced for the labor-related allocated percentage attributable to non-electric operations (as reflected in Instruction 2 of Schedule 9) before the remaining balances are allocated to ADIT in the FERC Formula Rate based on the FERC-related Transmission Wages & Salaries Allocation Factor percentage as reflected in Scheule 27, Line 9.

Q. Where in the Formula Rate are these calculations shown?

A. FERC Account 190 ADIT is calculated on Lines 100 to 353 of Schedule 9, and the total FERC-related account 190 ADIT adjustment to rate base is presented on Line 354 of Schedule 9. Account 282 ADIT is calculated on Lines 400 to 452 of Schedule 9, and the total FERC-related account 282 ADIT adjustment to rate base is presented on Line 453 of Schedule 9. Account 283 ADIT is calculated on Lines 500 to 803 of Schedule 9, and the total FERC-related account 283 ADIT adjustment to rate base is presented on Line 804 of Schedule 9.

Q. Are there adjustments to Rate Base that are attributable to Deferred Investment Tax Credit balances?

A. No. Under the tax normalization rules, SCE is required to treat deferred investment tax credits consistent with section 46(f)(2) of the Internal Revenue

Code, prior to its repeal. Pursuant to section 46(f)(2), investment tax credits are to be initially deferred and subsequently amortized as a reduction to income tax expense over the remaining book life of the property, and unamortized deferred investment tax credit balances are not to be included in the adjustment to Rate Base.

Q. Are there adjustments to the ADIT component of Rate Base that are attributable to deferred taxes that cannot be currently used by SCE?

A. Yes. SCE adjusts the ADIT component of Rate Base consistent with SCE's Private Letter Ruling ("PLR") 201438003 issued by the Internal Revenue Service ("Service") for deferred taxes that cannot be currently used by SCE. In this PLR, the Service concluded that it would be inconsistent with the tax normalization requirements for SCE to reduce Rate Base by the full ADIT liability balance without first reducing that full ADIT liability balance by the deferred tax asset attributable to a net operating loss carryover amount that represents tax benefits that cannot be utilized because of the resulting elimination of taxable income. When applicable, this adjustment is reflected in Line 116 of Schedule 9.

Q. How are the ADIT balances used to adjust Rate Base?

A. For purposes of calculating Prior Year TRR, the year-end balance of FERC-related ADIT is included in Line 5, Column 2 of Schedule 9 is used to adjust Rate Base. For purposes of calculating the True-Up Adjustment, the FERC-related ADIT balance is computed under the pro rata method as reflected and described in Lines 805 through 818 of Schedule 9, which is consistent with the tax normalization requirements of Treasury Regulations Section 1.167(l)-6(h)(6).

Q. Does the ADIT pro rata calculation no longer include the "two-step" 13-month averaging of those pro rata balances?

A. Yes. Consistent with Paragraph 34 of the Commission's Order On Paper Hearing,[4] the pro rata computation only includes the resulting ending pro rata balance without the additional "two-step" 13-month averaging.

IV. NET EXCESS DEFERRED INCOME TAX LIABILITY

Q. What is Net Excess Deferred Income Tax Liability?

A. The Net Excess Deferred Income Tax Liability ("NEDITL") represents the difference between: 1) ADIT balances recorded with the Federal income tax statutory rate of 35%, and 2) the ADIT balances recorded with the Federal income tax statutory rate of 21% as a result of the TCJA. To the extent that there is an ADIT asset (*i.e.*, debit) balance, the lower income tax rate results in a deficient deferred income tax asset. To the extent that there is an ADIT liability (*i.e.*, credit) balance, the lower income tax rate results in an excess deferred income tax liability. SCE's ADIT liability balances exceed its ADIT asset balances, which results in an NEDITL that is labeled on Line 4 in Schedule 9 as "Net Excess/Deficient Deferred Tax Liability/Asset – 2017 TCAJA" pursuant to Paragraph 21 of the Commission's Order Accepting Tariff Revisions, Subject to Condition.[5]

Q. What are the general implications of NEDITL on Rate Base?

A. The NEDITL balance reduces Rate Base. The FERC-related NEDITL balance is used to adjust rate base in the computations of Prior Year TRR, as reflected in

[4] *S. Cal. Edison Co.*, 165 FERC ¶ 61,241 (2018).

[5] *S. Cal. Edison Co.*, 166 FERC ¶ 61,006 (2019).

Line 4, Column 2 of Schedule 9, and included in the computation of the True Up Adjustment as reflected in Line 15, Column 2 of Schedule 9.

Q. Does SCE's FERC Form 1 provide information on NEDITL balances?

A. Yes. SCE's FERC Form 1 includes year-end unamortized NEDITL balances in FERC Account 254 [Other Regulatory Liabilities] that are used in the Formula Rate proceedings to calculate the NEDITL adjustment to Rate Base as reflected in Schedule 9. FERC Account 254 separately reflects the FERC-related unamortized NEDITL balance and the related tax gross-up balance on the unamortized NEDITL balance. The tax gross-up balance represents the tax benefits that will be provided to ratepayers when the NEDITL balance is amortized in rates under the ARAM method as reflected in Line 60 of Schedule 1. FERC Account 254 also reflects the combined balances of the CPUC-related NEDITL and related tax gross-up.

In addition, pursuant to Paragraph 38 of FERC's Policy Statement, issued in Docket No. 19-2-000,[6] disclosure within the notes to the FERC Form 1 will include, beginning in 2018, the FERC accounts affected by NEDITL, how the ADIT accounts were remeasured in determining the NEDITL, information on the reversal and eventual elimination of ADIT balances in those accounts, the NEDITL that is protected and unprotected, the accounts to which the NEDITL will be amortized, the general amortization period that the NEDITL will be returned through rates, and a summary of the manner by which NEDITL will be included in rates by rate jurisdiction.

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[6] *Accounting & Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset*, 165 FERC ¶ 61,115 (2018).

Q. How does the Formula Rate determine the NEDITL adjustment to Rate Base?

A. Schedule 9 of the Formula Rate pulls the year-end balance of the FERC-related unamortized NEDITL balance from FERC Account 254 of FERC Form 1 and includes this balance in Line 4, Column 2 of Schedule 9 for purposes of calculating Prior Year TRR. For purposes of calculating the True-Up Adjustment, the FERC-related unamortized NEDITL balance is imbedded in the beginning and ending ADIT/NEDITL balances used in the pro rata calculation as reflected in Lines 805 and 817, Column 3 of Schedule 9.

V. OTHER TAXES

Q. Please describe the Other Taxes component of the Prior Year TRR and True Up TRR

A. Other Taxes are the sum of FERC-related Payroll Tax Expense and Property Tax Expense that are calculated in Schedule 1, Lines 19 to 36. Payroll Tax Expense is an allocated portion of Total Electric Payroll Tax Expense using the W&S AF, in accordance with Commission policy. The Formula Rate reduces Total Electric Tax Expense by SCE's capitalized overhead amount before applying the W&S AF, to reflect the fact that SCE capitalizes a portion of the Electric Payroll Tax Expense stated in FERC Form 1. Property Taxes are an allocated portion of Total Property Taxes, using the Transmission Plant Allocation Factor. Total Electric Payroll Tax Expense and Total Property Tax Expense are the company total amounts reflected in FERC Form 1, both in Account 408.1.

Q. Does this conclude your testimony?

A. Yes, it does.

DECLARATION

I, Alfred L. Lopez, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 5, 2019 in Rosemead, California

Alfred L. Lopez

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
ROBERT G. MINDESS

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-12)

APRIL 2019

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
ROBERT G. MINDESS

(EXHIBIT SCE-12)

Mr. Mindess's testimony provides a detailed description of SCE's treatment of its Administrative & General Expense ("A&G Expense"), as well as its Franchise Fees Expense and Uncollectibles Expense, in its proposed Formula Rate. Mr. Mindess describes (1) generally what A&G Expense consists of and (2) how the proposed Formula Rate will recover A&G Expense based chiefly on a labor allocation factor. Mr. Mindess describes adjustments made to SCE's A&G Expense amounts reported in its annual FERC Form 1 filing with the Commission. Mr. Mindess discusses the various incentive compensation plans and recognition programs at SCE, how they are accounted for, and how they are recovered in the proposed Formula Rate. Mr. Mindess also discusses the proposed Formula Rate's A&G Expense, Franchise Fees Expense and Uncollectibles Expense schedule that will be filed as part of SCE's Formula Rate annual update filings.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)))**	**Dkt. No. ER19-______-000**

PREPARED DIRECT TESTIMONY OF ROBERT G. MINDESS ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Robert G. Mindess, and my business address is 8631 Rush Street, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Senior Advisor, Rates in the FERC Rates and Market Integration Division within Edison's Regulatory Affairs Department. My primary responsibilities include development of rates for services that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), and reviewing FERC-jurisdictional contracts to make sure they comply with current FERC policy.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts Degree in biology from the University of Colorado at Boulder, Colorado, and a Juris Doctor Degree from the Whittier College School of Law in Los Angeles, California. I have been a member of the California and Washington D.C. bars since 1993. I have been employed at SCE since 2007 in various positions, including Contract Manager and Project Manager, and have been in my present role since April 22, 2013.

Q. Have you submitted testimony to the Commission previously?

A. Yes. I have submitted testimony in Docket Nos. ER18-169 (SCE's Second Formula Rate Proceeding), as well as ER18-1207 and ER19-1480 (SCE's Transmission Access Charge Balancing Account Adjustment Updates for 2018 and 2019). My previous formula testimony has generally concerned SCE's treatment of Administrative & General expenses, as well as Franchise Fees Expense and Uncollectibles Expense factors.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the details of SCE's proposed determination of Administrative & General Expense ("A&G Expense"), its Franchise Fees Expense, and its Uncollectibles Expense ("FF & U Expense) within its proposed Formula Rate.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 20 (A&G) and Schedule 28 (FF&U).

II. OVERVIEW OF SCE'S A&G EXPENSE

Q. Please describe the Administrative and General Expense component of the proposed Formula Rate.

A. A&G Expense represents the costs of SCE's administrative and general corporate expenses, which are expenses that support the operation of the entire company. A portion of the A&G Expense is then allocated to the ISO transmission function and recovered through the Transmission Revenue Requirement ("TRR").

A&G Expense is calculated by applying allocation factors[1] to amounts

[1] *See* Sections VI and VII of the testimony of Antonio Ocegueda (Exhibit No. SCE-15) for an explanation of the Wages and Salaries and Plant Allocation Factors used in allocating total

recorded in the A&G accounts (Accounts 920-931 and 935). From these amounts, certain costs are excluded for various reasons that are described in greater detail below. The remaining cost amounts are allocated to the Prior Year TRR using the Transmission Wages and Salaries Allocation Factor ("Labor Allocator") for most accounts. The calculation of the Labor Allocator is discussed in the testimony of Antonio Ocegueda (Exhibit No. SCE-15). The exception is that Account 924 (Property Insurance) expenses are allocated using the Transmission Plant Allocation Factor ("Plant Allocator") in accordance with Commission policy. The calculation of the Plant Allocator is discussed in the testimony of Antonio Ocegueda (Exhibit No. SCE-15). As discussed below Franchise Fees Expense is a calculated value in the proposed Formula.

Q. Are there any cost categories that are excluded from the recorded FERC Form 1 A&G accounts in SCE's determination of its A&G Expense amount?

A. Yes. Certain costs are excluded from the recorded FERC Form 1 A&G accounts because they are: (1) paid for by SCE's shareholders; (2) franchise requirement costs in Account 927; (3) certain General Advertising Expenses in Account 930.1; (4) certain Miscellaneous General Expenses in Account 930.2; (5) certain post-retirement benefits other than pensions ("PBOPs") that are different than the specific amount authorized by the Commission; and (6) expenses that are covered 100% under California Public Utilities Commission ("CPUC") rates.

Q. Why are shareholder costs excluded from the recorded FERC Form 1 A&G accounts?

A. Shareholder costs are amounts that SCE has spent during the year on behalf of SCE's shareholders and that do not benefit SCE's ratepayers, and are therefore not included for recovery from SCE's ratepayers. An example of such a shareholder

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SCE A&G expenses to the ISO Transmission A&G Expenses recovered through the proposed Formula Rate.

cost is the expense amount for costs incurred to pay for the labor and other costs associated with the operation of an employee fitness center facility located at SCE's General Office Complex in Rosemead, California. These costs are excluded and are paid entirely by SCE's shareholders.

Q. Why are franchise requirement costs that are recorded in Account 927 excluded from the recorded FERC Form 1 A&G accounts?

A. Franchise Requirements costs are excluded because the proposed Formula Rate does not recover Franchise Requirements costs through its A&G Expense, but instead recovers these costs through another component of the TRR. This will be explained in detail later in Section III of this testimony.

Q. Why are certain General Advertising Expenses that are recorded in Account 930.1 excluded from the recorded FERC Form 1 A&G accounts?

A. Pursuant to Commission policy and its clarification through the *PATH* decision,[2] any costs in Account 930.1 (General Advertising Expense) that are related to advertising for civic, political and related activities, such as those designed to solicit public support or the support of public officials in matters of a political nature are excluded from the proposed Formula Rate. As such, SCE's proposed Formula Rate seeks to only recover general advertising expenses that are for safety, siting, or of an informational nature through this proposed Formula Rate, in the same manner as the Second Formula Rate.

Q. Why are certain Miscellaneous General Expense amounts that are recorded in Account 930.2 excluded from the recorded FERC Form 1 A&G accounts?

A. Account 930.2 contains expenses that are incurred in the general management of the company that are not provided for elsewhere. In SCE's Second Formula Rate, specific costs recorded in Account 930.2 were excluded from transmission rates.

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[2] *See Potomac-Appalachian Transmission Highline, LLC and PJM Interconnection*, LLC, 152 FERC ¶ 63,025 (2015), and FERC Docket Nos. ER09-1256-002 and ER12-2708-003.

SCE will continue this practice and not seek to recover certain miscellaneous general expense amounts through the proposed Formula Rate in accordance with Instruction 2 of Schedule 20 of Exhibit No. SCE-4. The specific items of excluded expenses that SCE will continue to exclude are: Provision for Doubtful Accounts – Non-Energy Billings; accounting suspense amounts; balance sheet write-offs of abandoned project expenses; nuclear power research expenses; annual report preparation expenses noted under "Pub & Dist Info to Stkhldrs;" other experimental and general research expenses that are not charged to other operation and maintenance expense accounts on a functional basis; any penalties or fines; and any costs recovered 100% through CPUC rates.

Q. Why are certain Post-Retirement Benefits Other Than Pensions ("PBOPs") amounts recorded in Account 926 that are different that the specific amount authorized by the Commission excluded from the recorded FERC Form 1 A&G accounts?

A. PBOPs Expense are those costs that SCE incurs for providing post-retirement medical, dental and vision coverage, Medicare Part B premium reimbursement and term life insurance coverage to its retirees. Pursuant to current Commission policy as noted in *Maine Yankee,*[3] a formula rate shall state a specific authorized amount of PBOPs Expense that a utility may recover each year. Accordingly, any difference between the actual PBOPs expense incurred during a year that is included in Account 926 and the Commission-approved amount of stated PBOPs

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3 *See Maine Yankee Atomic Power Company*, 43 FERC ¶ 61,453, at 61,923 (1988) (Commission policy requires PBOPs and Depreciation Rates to be specified, even if the utility operates under a formula rate. This is because PBOPs accounts are typically amounts that are amortized over a set period of time much like depreciation or decommissioning expenses. A modification in the amortization without Commission scrutiny can result in over-recovery or intergenerational inequities. A stated amount is needed to provide specificity in the calculation of formula rate, as it appears in the form of a rate schedule.).

Expense reflected in the formula rate is excluded from recovery. In the proposed Formula Rate, the initial amount of Authorized PBOPs Expense Amount is $18,219,000 as filed in Docket No. ER19-1226-000, which is currently pending before the Commission. (*See* Protocols, Section 8. b.)

Q. Do SCE employees have a component of their compensation that is based upon company performance?

A. Yes. Under SCE's Short-Term Incentive Plan ("STIP"), eligible employees have compensation opportunities that are market competitive and are intended to fairly compensate them for meaningful contributions to the Company's strategic business objectives of safely delivering reliable and affordable electricity to its customers. The amount an employee receives under STIP is a component of Non-Officer Incentive Compensation ("NOIC") in SCE's proposed Formula Rate. NOIC also includes the Key Contributor Incentive Plan. This plan provides principal level employees and senior attorneys (who are not eligible for the Company's Long Term Incentive Plan) with compensation opportunities based upon their impact to mid and long term results of the Company, and is used by SCE as a way to retain employees with a history of strong performance, critical skills and great future potential. The third component of NOIC is the Non-Officer Executive Incentive Compensation Plan. This plan provides executive employees that are not officers of SCE with a competitive compensation for their contributions to the goals and objectives of the Company.

Q. How does SCE account for NOIC?

A. NOIC expenses represent total company employee incentive payments that are recorded to Account 920 on an accrued basis in FERC Form 1. SCE initially accrues its NOIC expenses with the expectation that it will be fully paid out to employees and therefore reserves the total amount that could be owed under NOIC. As such, during the year, SCE accrues and records on its books for a 100%

or full NOIC payout based upon the sum of all target awards for all participants following the conclusion of the annual performance period (from January 1st through December 31st). The Compensation Committee of SCE's Board of Directors determines Company performance (referred to as the corporate modifier) following the end of the plan year. Each employee's NOIC payout equals the target award for their position, adjusted by the individual performance modifier for exempt employees and the corporate multiplier for all eligible employees. SCE adjusts its books to show that amount of approved NOIC, which will be that amount ultimately paid out to SCE's eligible employees in March after the end of the plan year. The amount of NOIC recorded in SCE's ledgers will have two components, a capitalized portion and a non-capitalized portion. The capitalized portion is included in workorders and ultimately is recorded to plant and included in SCE's rate base. That capitalized amount is then deducted from the total amount of approved NOIC to be paid out. The remaining non-capitalized amount of NOIC will be recovered through the proposed Formula Rate within the A&G Schedule as an allocated amount based upon the Labor Allocator.

Q. Describe the cash and non-cash recognition programs at SCE that are available to employees, and discuss how SCE proposes to treat recognition pay in its proposed Formula Rate?

A. SCE's recognition programs acknowledge employees for desired behaviors, such as achieving exceptional business results. SCE's cash and non-cash recognition programs are known as Spot Bonus and Encore, respectively.

The Spot Bonus program recognizes an individual or a team for delivering exceptional, measurable results, making significant contributions, developing a new or innovative program or process, or leading a Company-wide team or major project that notably exceeds expectations, within scheduled time frames and comes in under budget, which also leads to reduced expenses and ultimately, lower rates for SCE's customers. Spot Bonuses are also used to provide real-time rewards for those employees who accept and perform additional responsibilities in an exceptional manner or accept responsibilities or assignments that require extraordinary time commitments.

Encore uses points to award employees for promoting a safe working environment through their actions and behaviors, and for helping contribute to public safety. All non-executive employees are eligible to participate in this program.

Q. Do SCE executive officers have a component of their compensation that is based upon company performance?

A. Yes. Executive officers have an incentive pay plan that is tied to overall company performance. This plan is known as the Executive Incentive Compensation Plan ("EIC") and is referred to in SCE's proposed Formula Rate as the Officer Executive Incentive Compensation ("OEIC"). The EIC plan is part of the market competitive compensation package designed to attract and retain a well-qualified leadership team which best serves the needs of SCE's customers.

Q. How does SCE account for and recover OEIC?

A. For purposes of recovery of OEIC under SCE's proposed Formula Rate, it is treated in the same manner as NOIC in that there will be an accrued amount of OEIC shown on SCE's ledgers, which is then adjusted to reflect the actual amount of OEIC as determined by SCE's Board of Directors. Further, there are capitalized and non-capitalized portions of OEIC, which is handled for recovery purposes in the same manner as that described above for NOIC.

Q. Does SCE have a long term incentive pay mechanism?

A. Yes. SCE also has another variable component of executive employees' compensation known as the Long Term Incentive Plan ("LTI"). LTI includes non-qualified stock options, restricted stock units, and performance shares, with multi-year vesting periods from three to four years. LTI is dependent upon a number of factors including multiple years of continuous employment, strong job performance at the executive level, and financial health of the Company. LTI grants are provided as a means to incentivize executives to conduct themselves and to make decisions that lead to safer and more reliable service and to encourage the development of just and reasonable electrical rates that inures to the benefit of SCE's ratepayers. As such, LTI grants are properly recoverable in SCE's transmission rates.

Q. Describe SCE's Executive Retirement Plan.

A. SCE executives are eligible for its non-qualified pension plan known as the Executive Retirement Plan ("ERP") (which is known as the Supplemental Executive Retirement Plan ("SERP") in SCE's proposed Formula Rate). The SERP provides benefits that executives cannot receive from the qualified SCE Retirement Plan due to compensation and payout limits imposed by the Internal Revenue Code on that plan. The compensation recognized for plan purposes is base pay, except for elected officers, where compensation is base pay plus bonus. Effective January 1, 2018, the Executive Retirement Account (ERA) was created within ERP. ERA provides eligible executives bonus credits and salary credits on the salary amount that exceeds the IRS compensation limit. In the proposed Formula Rate, SCE will incur $15,341,690 in SERP Expense (*see* attached Schedule 20 Workpaper, Line 1, Calculation of SERP Expense, Page 5 of 10 of Exhibit No. SCE-29).

Q. Is SCE proposing any adjustment to A&G Expenses as a result of Senate Bill (SB) 901?

A. No. In 2018 the legislature of the state of California enacted, and then Governor Brown signed, SB 901, which amended Section 706 to the California Public Utilities Code. Section 706 provides that electrical corporations shall not recover compensation for its corporate officers in state-jurisdictional rates. As Section 706 does not apply to rates approved by the Commission, SCE will continue to recover compensation for its officers through the proposed Formula Rate. The rates sought herein shall contain executive compensation expense amounts in FERC Account 920 and executive incentive compensation benefits in FERC Account 926 through the proposed Formula Rate. Further, SCE is proposing no changes from the Second Formula Rate with respect to A&G Expenses.

III. OVERVIEW OF FRANCHISE FEES AND UNCOLLECTIBLES EXPENSES

Q. Please describe the Franchise Fees component of the Prior Year TRR.

A. Franchise Fees represent the payments that SCE makes to municipal entities for the right to locate its electric facilities within the municipality. The proposed Formula Rate determines Franchise Fees Expense by applying the Franchise Fee Factor, as approved by the CPUC, to the components of the Base TRR, including the Prior Year TRR calculated on Schedule 1 (Line 79), the Incremental Forecast Period TRR calculated on Schedule 2 (Line 79), and the True Up TRR calculated on Schedule 4 (Lines 42-43). In the proposed Formula Rate, the Franchise Fees allocation factor is 0.92057% (*see* Exhibit No. SCE-4, Schedule 28, Line 5) and the total amount of Franchise Fees Expense is $11,448,143 (See Exhibit No. SCE-4, Schedule 1, Line 79). The Wholesale Difference to the Base TRR includes the amount of Franchise Fees Expense included in the Base TRR as a reduction that will reduce the Wholesale Base TRR (Exhibit No. SCE-4, Schedule 25, Line 44).

Q. Please describe the Uncollectibles component of the Prior Year TRR.

A. The proposed Formula Rate determines Uncollectibles Expense by applying the CPUC-approved Uncollectibles Expense Factor to the total of the above-mentioned TRR components. In the proposed Formula Rate, the Uncollectibles Expense allocation factor is 0.24076% (*see* Exhibit No. SCE-4, Schedule 28, Line 5), and the total amount of Uncollectibles Expense is $2,994,074 (*see* Exhibit No. SCE-4, Schedule 1, Line 80). The proposed Formula Rate determines Uncollectibles Expense by applying the Uncollectibles Factor, as approved by the California Public Utilities Commission ("CPUC"), to the components of the Base TRR, including the Prior Year TRR calculated on Schedule 1 (Line 80), the Incremental Forecast Period TRR calculated on Schedule 2 (Line 80), and the True UP TRR calculated on Schedule 4 (Lines 44-45) of Exhibit No. SCE-4.

Q. Why is Uncollectibles Expense excluded from the Wholesale Base TRR?

A. Uncollectibles Expenses represents billed retail revenue that SCE does not collect. Uncollectible Expense is included in SCE's retail Base TRR through an addition of an amount based on the Uncollectibles Expense Factor as a last step once all other components to the Base TRR are calculated. However, Uncollectibles Expense represents amounts charged to retail customers but not ultimately collected. Accordingly, it is inappropriate to include it as a component of the Wholesale Base TRR. The Wholesale Difference to the Base TRR includes the amount of Uncollectibles Expense included in the Base TRR as a reduction that will reduce the Wholesale Base TRR (Exhibit No. SCE-4, Schedule 25, Lines 41 and 42).

Q. Does SCE propose any changes in its recovery of Franchise Fees Expense and Uncollectibles Expense in the attached proposed Formula Rate or protocols at this time?

A. No. The proposed Formula Rate schedule and protocols are unchanged from the Second Formula Rate with respect to recovery of Franchise Fees Expense and Uncollectibles Expense. Only the inputs will be updated when the CPUC authorizes new factors. These factors are reviewed every three years in SCE's CPUC General Rate Case. SCE identifies the revision of FF&U factors as a "single issue" adjustment pursuant to the proposed Protocols.

IV. FORMAT OF THE SCHEDULE AND WORKPAPERS FOR A&G EXPENSE

Q. Please describe the Format of Schedule 20-A&G of the Formula Rate spreadsheet.

A. Schedule 20 of the Formula Rate Spreadsheet (Exhibit No. SCE-4) is the schedule that calculates A&G Expense in SCE's proposed Formula Rate. Items that are inputs to the Formula Rate Spreadsheet are shaded yellow. These yellow-shaded cells are the only parts of the Formula Rate Spreadsheet that SCE may revise each year during its Annual Update filing process. The source of each ultimate input is tied to SCE's FERC Form 1 filing, or, when specifically noted, to SCE's internal records. The amounts and associated calculations that are contained within Schedule 20 come from the workpaper for Schedule 20 contained within Exhibit No. SCE-29.

Schedule 20 shows the total A&G Expense broken down into its component FERC Accounts, and the amounts excluded from SCE's FERC Form 1 filing for accounts 920-935. Then further deductions and exclusions are made so that the amount of SCE's A&G Expenses are shown. The Schedule's Notes show the itemization of exclusions, the NOIC Adjustment, and the PBOPs Exclusion

Calculation.

In the proposed Formula Rate, that amount of A&G expense to be included for recovery in the Base TRR for 2019 is $52,386,525 (See Exhibit No. SCE-4, Schedule 20, Line 23).

Q. Please describe the workpapers for Schedule 20.

A. The supporting workpaper for the A&G Expense schedule is a Spreadsheet with a series of tabs which itemize the exclusion amounts by category type and FERC Account number.

Shareholder and Other tab: The Shareholder and Other tab of the Schedule 20 workpaper spreadsheet supports the shareholder and other exclusions that SCE will be taking from its FERC Form 1 recorded amounts, which is itemized by FERC Account number.

Incentives tab: The Incentives tab of the Schedule 20 workpaper spreadsheet supports the adjusted amount of incentive compensation that SCE will recover broken out by each plan or program.

ShareholderExcDetail tab: The ShareholderExcDetail tab in the Spreadsheet supports SCE's shareholder exclusions by FERC Account and provides descriptions of each exclusion.

Acct 930.2 tab: This tab in the Schedule 20 workpaper spreadsheet contains a table which shows the items of Miscellaneous General Expenses contained in SCE's FERC Form 1 filing (page 335), and shows what expense items are included or excluded as well as the Formula Reference of each. In SCE's proposed Formula Rate, the Acct 930.2 tab from SCE's workpaper is shown on Page 9 of 9 is reproduced here:

FERC Form 1 Pg. 335 Line #	Description	FERC Form 1 Amount	Included	Excluded	Formula References
1	Industry Association Dues	$2,062,759	$2,062,759	-$208,296	Sch. 20, Line 35
2	Nuclear Power Research Expenses			$0	
3	Other Experimental and General Research Expenses	$20,983,266	$0	$20,983,266	Sch. 20, Line 35
4	Pub & Dist Info to Stkhldrs…expn servicing outstanding Securities	$622,266	$622,266	$0	
5	Other Expn >=$5,000 show purpose, receipt, amount. Group if < $5,000				
6	Credit Line Fees / Bank Charges	$3,769,654	$3,769,654	$0	
7	Directors' Fees and Expenses	$2,894,700	$2,894,700	$0	
8	Periodic SEC Reports	$460,395	$460,395	$0	
9	Planning and Development of Communication Systems	$1,395,355	$1,395,355	$0	
10	Provision for Doubtful Accounts - Non-Energy Billings	-$241,090	$0	-$241,090	Sch. 20, Line 35
11	Vendor Discounts	-$9,766,562	-$9,766,562	$0	
12	Accounting Suspense	-$420,073	$0	-$420,073	Sch. 20, Line 35
13	Miscellaneous	-$1,456,115	-$3,112,624	$1,656,509	Sch. 20, Line 35
14					
15	Payment to CEC / CPUC	$0		$0	Sch. 20, Line 35
16	Administrative and General Expense Charged or Paid to Others	$11,883,138	$11,883,138	$0	Sch. 20, Line 35
17	Balance Sheet Write-Off	$2,234,679	$0	$2,234,679	Sch. 20, Line 35
46	Total	$34,422,372	$10,209,081	$24,004,996	

V. FORMAT OF THE SCHEDULE AND WORKPAPERS ASSOCIATED WITH FF&U EXPENSE

Q. Please describe the format of Schedule 28-FF&U of the Formula Rate Spreadsheet.

A. This schedule contains the Franchise Fee and Uncollectibles Factors used in the new formula rate mechanism to calculate Franchise Fees Expense and Uncollectibles Expense. Schedule 28 of Exhibit No. SCE-4 lists the Approved Franchise Fees Factor and the Approved Uncollectibles Expense Factor as determined through SCE's General Rate Case proceedings at the CPUC.

Q. Does this conclude your testimony?

A. Yes, it does.

DECLARATION

I, Robert G. Mindess, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 5, 2019 in Rosemead, California

Robert G. Mindess

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
JEE KIM

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-13)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
JEE KIM

(EXHIBIT SCE-13)

Ms. Kim discusses Southern California Edison Company's ("SCE") formulaic dertermination of the Revenue Credits component for the Prior Year Transmission Revenue Requirement ("TRR") and True Up TRR, including the component relating to the Gross Revenue Sharing Mechanism.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
JEE KIM
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Jee Kim, and my business address is 8631 Rush Street, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Senior Rates Advisor in the FERC Rates & Market Integration Division within Edison's Regulatory Affairs organizational unit. My primary responsibilities include providing analysis and policy guidance supporting the development of pricing and related rate terms associated with contracts and services subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC" or "Commission").

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts degree in Economics from the University of California Irvine in September 2003. In February 2008, I joined SCE as a Financial Analyst in the Regulatory Policy and Affairs Department, where my responsibilities included supporting the development of the stated rate case and annual Formula Updates, supporting the development of the annual filing for SCE Construction Work In Progress ("CWIP") Balancing Account, and supporting the development of Wholesale Distribution Access Charges for wholesale load customers.

Q. Have you submitted testimony to the Commission previously?

A. Yes, I sponsored testimony in Docket Nos. ER18-154, ER18-169, and ER19-220. My prior testimonies supported the Second Formula Rate's determination of the Revenue Credit component of the Base TRR and the last two annual updates of SCE's Transmission Revenue Balancing Account Adjustment ("TRBAA") and associated TRBAA rate.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony supports the calculation of Schedule 21 in the proposed Formula Rate. The purpose of my testimony is to explain: 1) the proposed formulaic determination of the Revenue Credits component of the Prior Year Transmission Revenue Requirements ("TRR") and True Up TRR, including the component relating to the Gross Revenues Sharing Mechanism ("GRSM");
2) the California Public Utilities Commission ("CPUC") approved GRSM and the determination of the ratepayer share of Other Operating Revenue ("OOR") from non-tariffed products and services ("NTP&S") pursuant to the GRSM; and 3) the calculation of Revenue Credits on Schedule 21 of the proposed Formula Rate to be in the Prior Year TRR and True Up TRR.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 21 (Revenue Credits).

Q. Is SCE proposing any changes to Schedule 21 relating to the TO2018 Formula Rate?

A. SCE is proposing no methodological or formulaic changes to the proposed treatment of OOR or GRSM from the Second Formula Rate.

II. REVENUE CREDITS

Q. What are Revenue Credits?

A. Revenue Credits consist of revenues received by SCE from sources other than the sale of electric power. Most of this revenue is recorded in FERC Accounts 450 through 457. Revenue Credits received from non-utility operations or from subsidiaries is recorded in FERC Accounts 417 and 418.1, respectively. Depending on the activity generating the Revenue Credits, such revenue is either returned entirely to ratepayers or shared between ratepayers and shareholders.

Q. Please describe the various FERC Accounts in which Revenue Credits are booked.

A. FERC Account 450, Forfeited Deposits, and FERC Account 451, Miscellaneous Service Revenues, are related to the provision of retail service and include revenues from charges adopted by the CPUC associated with the establishment and maintenance of electric service for SCE's retail customers. FERC Account 453, Sales of Water and Water Power, contains revenues received for sales of power from SCE's hydroelectric projects. FERC Account 454, Rent from Electric Property, contains revenues received from the use by others of land, buildings, and other property. FERC Account 456, Other Electric Revenues, is composed of various items not included in FERC Accounts 450, 451, 453 and 454. FERC Account 456.1, revenues from Transmission of Electricity of Others, contains revenues received for transmission service to third parties over SCE's transmission facilities which includes Existing Transmission Contract

("ETC") revenues. FERC Account 457.1, Regional Transmission Service Revenues, contains revenues received from scheduling, control, and dispatching services provided by SCE. FERC Account 457.2, Miscellaneous Revenues, contains revenues and reimbursements received for costs incurred by regional transmission service providers not provided for elsewhere. FERC Account 417, Revenues from Nonutility Operations, contains revenues received from activities not related to utility service but that are nonetheless part of SCE. FERC Account 418.1, Equity in Earning of Subsidiary Companies, contains revenues from subsidiary companies.

Q. How are Revenue Credits treated in the proposed Formula Rate?

A. Revenue Credits are calculated in Schedule 21 of the proposed Formula Rate and are an input to both the Prior Year TRR (a component of the Base TRR, which is the projected rate charged to customers, and which is calculated in Schedule 1), and the True Up TRR (SCE's actual costs of service for the Prior Year, which is calculated in Schedule 4). Revenue credits are a reduction to the Prior Year TRR (Schedule 1, Line 72) and to the True Up TRR (Schedule 4, Line 33).

Revenue credits can be categorized into two different types. The first comes from traditional revenue generating activities that have historically been classified as other operating revenue. This type of revenue ("Traditional OOR") is returned 100% to ratepayers as a credit to Prior Year TRR and True Up TRR. The second category is revenue derived from non-tariffed products and services ("NTP&S") activities subject to the CPUC-approved GRSM. GRSM revenue is shared between ratepayers and shareholders according to percentages prescribed under the mechanism. Like Traditional OOR, the ratepayers' share of GRSM revenue is a credit to the Prior Year TRR and True Up TRR.

Q. How are Revenue Credits calculated?

A. As described in detail below, the Revenue Credits schedule (Schedule 21) in the proposed Formula Rate calculates the total Traditional OOR and GRSM Revenue Credit to retail and wholesale ratepayers that take service over the facilities owned by SCE, but under Operational Control of the California Independent System Operator ("ISO"), to be used as a credit against the Prior Year TRR and True Up TRR. I will address both types of Revenue Credits, and explain how each is calculated under the formula rate.

III. TRADITIONAL OOR

Q. How was the Traditional OOR component of Revenue Credits developed in the proposed Formula Rate?

A. First, SCE identified and listed in Schedule 21 all revenue accounts currently generating either Traditional OOR or GRSM revenue. The accounts are listed by account, description and category (any new revenue accounts would be included in the Annual Update filing). Second, the formula calls for the jurisdictional allocation of revenue from Traditional OOR accounts involving ISO facilities between ISO and non-ISO ratepayers (Schedule 21, Columns F-H), based on what accounts involve ISO facilities. Finally, the revenue allocable to ISO ratepayers is included in the Revenue Credit to ISO ratepayers under the formula transmission rate (Schedule 21, Line 44).

Schedule 21 further identifies any Traditional OOR account that is handled via an existing balancing account. Such OOR accounts are labeled as Other Ratemaking Accounts. The formula does not credit ISO ratepayers with any revenue from Other Ratemaking Accounts associated with FERC balancing accounts, as this revenue is flowed back to ISO ratepayers via such balancing accounts. Any revenue from Other Ratemaking Accounts associated with

CPUC balancing accounts attributable to ISO facilities is listed under column G, Traditional OOR – ISO, and credited back to ISO ratepayers in the same manner as Traditional OOR. The formula provides for the jurisdictional allocation of these amounts based on either the currently approved CPUC Base Revenue Requirement Balancing Account (BRRBA) allocator (Column N, Note 12), or the CPUC GRC allocator (Column N, Note 7).

Q. Please identify all Traditional OOR accounts that were identified as utilizing ISO facilities and indicate how the revenue allocable to ISO ratepayers were determined.

A. The following table summarizes the Traditional OOR accounts utilizing ISO facilities and how the revenue was allocated to ISO ratepayers.

FERC ACCT	Ledger ACCT #	Activity	Description	Category	Revenue Allocation
454	4184810	Facility Cost - EIX/Nonutility	Revenue received from non-utility operations for labor and use of facilities devoted to utility operations.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
454	4184820	Rent Billed to Non-Utility Affiliates	Rental revenue received from non-utility affiliates.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
454	4194135	Interconnect Facility Finance Charge	Revenue received from customers for use of ISO and non-ISO facilities.	Traditional OOR	Review of facilities providing service.
454	4184821	Rent Billed to Utility Affiliates	Rental revenue received from utility affiliates.	Traditional OOR	Portion of revenue allocated to ISO based on CPUC allocator
454	4184811	Facility Cost-Utility	Revenue received from subsidiaries for labor and use of facilities devoted to utility operations.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
456	4186155	Non-Utility Subs Labor Markup	Markup of labor charges to non-utility subsidiaries.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
456	4196176	Interconnect Facility Finance Charge	Revenue received from customers for use of ISO and non-ISO facilities.	Traditional OOR	Review of facilities providing service.
456	4186156	Non-Utility Subs Labor Markup	Markup of labor charges to non-utility subsidiaries.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator

456	4186128	Misc ISO Revenue	Revenue from the sale of Four Corners to APS.	Traditional OOR	Direct assignment to ISO
456.1	4198110	Transmission of Elec of Others	Revenue from existing transmission contracts utilizing ISO facilities.	Traditional OOR	Direct assignment to ISO
418.1		Edison Material Supply (EMS)	Subsidiary revenue	Traditional OOR	Portion of revenue allocated to ISO based on CPUC allocator

Q. Are you proposing any changes to the method for allocating the amount of revenue allocable to ISO ratepayers for the items tabulated above?

A. No. The allocations are identical to the Second Formula Rate.

Q. What are the two primary drivers of the Traditional OOR allocated to ISO during 2017?

A. The primary driver of the Traditional OOR allocated to ISO are the ETC revenues. The ETC revenues contributes $46.3 million out of the $58.8 million.

Q. On what basis was it determined that the remaining Traditional OOR accounts listed in Schedule 21, not listed in the table above did not contain revenue attributable to ISO ratepayers?

A. The remaining Traditional OOR accounts were determined to not involve ISO facilities for one of the following reasons:

1. The activity involved was related to CPUC jurisdictional services.
2. The activity involved was related to generation.
3. The activity involved was related to Non-ISO facilities.

Column N of Schedule 21 indicates the specific reason for each of the accounts not containing revenue allocable to ISO ratepayers.

IV. NTP&S ACTIVITIES SUBJECT TO GRSM

Q. Please explain NTP&S.

A. Generally speaking, NTP&S are products and services other than traditional electric services that SCE offers to third parties that make secondary or complementary use of temporarily available capacity in utility assets and personnel. This temporarily available capacity may result from varying patterns of utilization, the need to plan for future utility-related growth, or the development of compatible secondary uses of the utility assets. NTP&S are offered at market-based prices that are not regulated by either the CPUC or the FERC. A complete list of SCE's NTP&S categories and a description of each is contained in Exhibit SCE-14. (Attaching CPUC tariff pursuant to CPUC Decision No. 99-09-070) In many cases, the offering of these NTP&S requires significant incremental costs (expense and capital). These incremental costs are not allocated to either retail or wholesale ratepayers; 100% of the incremental costs are borne by SCE's shareholders.

Q. What are the criteria for designating an NTP&S category as Passive or Active?

A. NTP&S categories designated as Passive are typically those in which SCE does not actively participate in the business activity for which the utility assets are being utilized for secondary purposes, or where SCE shareholders contribute little to no capital or resources in the business opportunity. NTP&S categories designated as Active are typically those where SCE takes an active role in the business for which the utility assets are being used for secondary purposes where SCE shareholders contribute new capital or resources in the opportunity.

Q. Please describe how the incremental costs associated with generating NTP&S gross revenues are treated.

A. Under the GRSM, all incremental costs (expense or capital) associated with the offering of NTP&S are the responsibility of, and allocated to, SCE's shareholders, not its ratepayers. Incremental costs are defined as those costs that would not be incurred "but for" the offering of the NTP&S. For example, in the leasing of a right-of-way for a mini-storage facility, the original cost of the land would not be an incremental cost because ratepayers are still getting the full usage of the land for utility purposes and the use of the land for a complementary, secondary use does not increase the ratepayers' costs associated with the land. However, if SCE is required to pay fees to re-zone the land for a mini-storage site, the fees would constitute incremental costs and would be the responsibility of shareholders, not ratepayers. In addition, shareholders are responsible for any liabilities associated with SCE's NTP&S offerings. Ratepayers are responsible for none of the incremental costs or risks associated with NTP&S.

Q. What is the impact to ratepayers if in a given year incremental costs exceed NTP&S gross revenues?

A. There is no impact on ratepayers. If SCE's incremental costs are greater than its NTP&S gross revenues, ratepayers still receive their same share of gross revenues under the GRSM. Under the GRSM, ratepayers are not impacted by the level of incremental costs or risks incurred by SCE in the offering of NTP&S.

Q. Please explain GRSM.

A. The GRSM is a mechanism adopted by the CPUC[1] for the sharing between ratepayers and shareholders, on a gross revenue basis, of certain OOR revenues that SCE receives from NTP&S activities. Under this mechanism, all incremental costs associated with NTP&S are allocated to shareholders.

The CPUC-adopted GRSM also establishes a threshold gross revenue credit to ratepayers ("GRSM Threshold") of $16.671 million from NTP&S. Since the

1 GRSM adopted by the CPUC in Decision 99-09-070 issued on September 16, 1999.

entire amount of the GRSM Threshold is a credit to SCE's customer rates, it guarantees ratepayer benefit from the mechanism.

The CPUC-jurisdictional share of the GRSM Threshold is reflected as a revenue credit on a forecast basis in SCE's revenue requirement in its CPUC general rate cases. Pursuant to the proposed FERC Formula, a share of the GRSM Threshold is flowed thru to ratepayers as Revenue Credit on Schedule 21.

Incremental gross revenues in excess of the GRSM Threshold ("Incremental Gross Revenues") are subject to sharing between SCE's shareholders and ratepayers based on a CPUC-prescribed methodology under the GRSM. Each of the NTP&S categories identified under GRSM is designated as either "Active" or "Passive." On an annual basis, once the pre-established GRSM Threshold has been met, ratepayers receive 10 percent of the Incremental Gross Revenues for Active categories (Schedule 21, Line 37) and 30 percent for Passive categories (Schedule 21, Line 40). The CPUC-jurisdictional portion of the ratepayers' share of the Incremental Gross Revenues is flowed through to ratepayers on a recorded basis through operation of a balancing account mechanism. The proposed FERC Formula flows a share of the Incremental Gross Revenues through Schedule 21.

Q. Does the GRSM address the sharing between ISO and non-ISO ratepayers?

A. No. The CPUC adopted GRSM does not address the jurisdictional allocation of the ratepayers' share of NTP&S revenue.

Q. How does the proposed Formula Rate allocate the ratepayers' share of GRSM revenue between ISO and non-ISO ratepayers?

A. The proposed Formula Rate utilizes the historical jurisdictional allocation of the GRSM Threshold, and applies this same FERC allocation percentage to Incremental Gross Revenues (Schedule 21, Line 41).

Q. Why was the GRSM Threshold established?

A. The $16.671 million GRSM Threshold represents the historical base amount of gross revenues associated with NTP&S that were reflected on a forecast basis in SCE's retail rates at the time the GRSM was adopted. Since ratepayers were already receiving 100% of these revenues as a revenue credit, the GRSM Threshold was established to ensure that ratepayers continued to receive, at a minimum, this level of historical revenues. However, any incremental costs associated with these revenues are now paid 100% by shareholders. In order to ensure that ratepayers continue to receive the GRSM Threshold, it is flowed through 100% to ratepayers as a revenue credit in SCE's rate cases and is not shared with shareholders. These revenues are credited to ratepayers' rates regardless of the level of actual NTP&S gross revenues.

Q. Please explain the jurisdictional allocation of the GRSM Threshold.

A. The current jurisdictional allocation approved by the CPUC assigns $5,425,127 as a revenue credit to ISO ratepayers, and this is reflected in Schedule 21, Line 34. The jurisdictional split of the GRSM Threshold results in approximately 32.5% being allocated to ISO ratepayers (Schedule 21, Line 41).

Q. Why is it reasonable to apply the historical jurisdictional allocation of the GRSM Threshold to Incremental Gross Revenues?

A. The proposed Formula Rate allocates Incremental Gross Revenues to FERC-jurisdictional transmission ratepayers in the same proportion that the GRSM

Threshold is allocated (32.54 %). Such allocation rate is reasonable since the Incremental Gross Revenues are derived from many of the same services that generate the GRSM Threshold, which rely on assets common to the transmission and distribution functions. Under the GRSM, an individual service is not classified as either part of the GRSM Threshold or Incremental Gross Revenues. In addition, as described above, the jurisdictional allocation of the Threshold Amount was based on a functionalization that reviewed individual functions that utilize different utility assets - some transmission, some distribution, some generation and some a combination. In this sense, the functions that generate the GRSM Threshold share the same characteristics as the functions that generate the Incremental Gross Revenues.

Q. Why should SCE shareholders receive any of the Incremental Gross Revenues?

A. The GRSM was designed to create a fair and equitable mechanism that incentivized SCE to expand its NTP&S to generate revenues for both ratepayers and shareholders. In addition, the GRSM was designed to provide sufficient long-term certainty regarding the treatment of NTP&S revenues and incremental costs so that SCE could evaluate whether or not to invest shareholder capital into NTP&S. Since shareholders are responsible for all incremental costs (expense and capital), they need to receive a portion of the Incremental Gross Revenues to cover these incremental costs and any incremental taxes incurred as well as to provide an incentive to take risks and pursue NTP&S opportunities. In addition, shareholders assume all of the risks and liabilities associated with NTP&S. The gross revenues from NTP&S were generated as a result of considerable work, sound decision-making, proper incentives and the expenditure of shareholder funded incremental costs. The ratepayers receive their share of Incremental Gross Revenues despite paying none of the incremental costs, taking none of the risk and having no responsibility for any of the liabilities associated with NTP&S.

Q. Please summarize how the GRSM has operated since its inception in 1999.

A. As shown in Table 1, since the inception of the GRSM through 2017, SCE has generated approximately $1,590.4 million in total gross revenues from NTP&S. Under the GRSM, ratepayers have received revenue credits of $516.8 million, $300.6 million through the annual GRSM Threshold and an additional $216.2 million as their share of the Incremental Gross Revenues. While shareholders have received $1,073.6 million of the Incremental Gross Revenues, they have also incurred $745.6 million in incremental costs and an estimated $132.6 million in incremental taxes associated with NTP&S. On a net basis, shareholders have received $195.4 million compared to ratepayers who have received $516.8 million. Thus, over the life of the GRSM, ratepayers have received 73% of the net revenues compared to shareholders 27%.

Table 1

Southern California Edison Company

Gross Revenue Sharing Mechanism

Summary of Operations

($ Millions)

Line		1999*	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
1	Total Gross Revenue	16.0	66.1	78.0	74.4	88.8	76.4	83.6	93.8	108.4	100.6	95.7	91.3	98.6	93.9	92.1	82.9	84.7	81.7	83.4	1590.4
2	GRSM Threshold	N/A	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	300.6
3	Total ratepayers' Share of Incremental Gross Revenues	2.7	8.0	9.8	9.9	11.2	10.6	11.7	12.7	16.6	13.6	13.0	12.5	13.5	12.8	12.0	11.1	11.4	11.2	11.9	216.2
4	Total ratepayers' Net Benefits (Line 2 + Line 3)	2.7	24.7	26.5	26.6	27.9	27.3	28.4	29.4	33.3	30.3	29.7	29.2	30.2	29.5	28.7	27.8	28.1	27.9	28.6	516.8
5	Shareholders' Share of Incremental Gross Revenues (Line 1 - Line 4)	13.3	41.4	51.5	47.8	60.9	49.1	55.2	64.4	75.1	70.3	66.0	62.1	68.4	64.4	63.4	55.1	56.6	53.8	54.8	1073.6
6	Total Incremental Costs (Allocated to Shareholders)	13.2	42.1	46.4	38.9	33.3	36.6	38.3	49.1	58.7	49.5	43.6	42.4	45.7	42.0	39.8	29.4	27.8	33.8	35.2	745.6
7	Pre-Tax Shareholders' Net Revenues (Line 5 - Line 6)	0.1	-0.7	5.1	8.9	27.6	12.5	16.9	15.3	16.4	20.8	22.4	19.7	22.7	22.4	23.7	25.7	28.8	20.0	19.6	328.0
8	Taxes (Line 7 * Tax Rate)**	0.0	-0.3	2.1	3.6	11.1	5.0	6.8	6.2	6.6	8.3	9.1	8.0	9.2	9.1	9.6	10.4	11.7	8.1	8.0	132.6
9	Total Shareholders' Net Revenues (Line 7 - Line 8)	0.1	-0.4	3.0	5.3	16.5	7.5	10.1	9.1	9.8	12.5	13.3	11.7	13.5	13.3	14.1	15.3	17.1	11.9	11.6	195.4
10	**Ratepayer' Share of Net Revenues (Line 4) / (Line 4 + Line 9)**	**96%**	**100%**	**90%**	**83%**	**63%**	**78%**	**74%**	**76%**	**77%**	**71%**	**69%**	**71%**	**69%**	**69%**	**67%**	**65%**	**62%**	**70%**	**71%**	**73%**
11	**Shareholders' Share of Net Revenues** (100% - Line 10)	**4%**	**N/A**	**10%**	**17%**	**37%**	**22%**	**26%**	**24%**	**23%**	**29%**	**31%**	**29%**	**31%**	**31%**	**33%**	**35%**	**38%**	**30%**	**29%**	**27%**

* Reflects partial year since GRSM effective 9/16/99

** The following tax rates were used 1999-2002: 40.551%; 2003- 2005: 40.370%; 20067-2008: 40.146%; 2009-2017: 40.588%

Q. Why should SCE's GRSM be adopted as part of the proposed Formula Rate?

A. As demonstrated above, under SCE's GRSM, ratepayers have received 73% of the net revenues from SCE's NTP&S. Ratepayers have received these revenues without incurring any of the incremental costs or risks associated with the NTP&S. In addition, the historical performance of the GRSM has demonstrated that it provides sufficient incentives to SCE to incur both the incremental expenses and capital that are required to offer the NTP&S.

Q. How is the GRSM component of Revenue Credits developed in the proposed Formula Rate?

A. First, SCE has identified and listed in Schedule 21 all NTP&S accounts and designated them as either Active or Passive pursuant to the GRSM (any new NTP&S accounts would be included in the Annual Update filing). Second, SCE has identified the gross revenues received as either GRSM Threshold (Column K, labeled "Threshold") or Incremental Gross Revenues (Column L, labeled "Incremental"). The first $16.671 million in gross revenue that is received in a given year is automatically recorded as GRSM Threshold. All additional gross revenues above the threshold amount are recorded as Incremental Gross Revenues. Third, SCE has determined the ratepayers' share of Incremental Gross Revenues according to the Active/Passive sharing percentages prescribed by the GRSM (Schedule 21, Lines 36 thru 42). Ratepayers receive 10% of Active Incremental Gross Revenues, and 30% of Passive Incremental Gross Revenues. Fourth, ISO ratepayers are allocated 32.5% of the GRSM Threshold. ISO ratepayers are also allocated 32.5% of the ratepayers' share of Incremental Gross Revenues. Finally, the GRSM revenue allocated to ISO ratepayers is included in the Revenue Credit to ISO ratepayers under this formula transmission rate (Schedule 21, Line 44).

Q. Does SCE's proposed Formula Rate Protocols address the GRSM mechanism?

A. Yes, the GRSM is called out in the proposed Formula Rate Protocols as single-issue Section 205 filing. The Protocols provide that if the CPUC adopts revisions to the GRSM, SCE will make a filing with the Commission to make conforming change to Schedule 21. It is necessary for the GRSM to be consistent in both the CPUC and FERC jurisdictions to assure fair treatment to both SCE's ratepayers and shareholders. Inconsistent treatment of the NTP&S revenues in the two jurisdictions could result in unnecessary litigation over allocation of such revenue, or dissuade SCE ratepayers from continuing to pursue NTP&S.

Q. Are you supporting the development of any workpapers in the proposed Formula Rate?

A. Yes, I am supporting the development of the One Time Adjustment to Prior Period True Up TRR workpaper to Schedule 3. In the proposed Formula Rate the One Time Adjustment to Prior Period True Up TRR is $137,652, as shown on Schedule 3, Line 12, Column 4.

V. CONCLUSION

Q. What are SCE's total Revenue Credit Amounts for 2017 attributable to this Formula Rate filing?

A. SCE's total Revenue Credits is $58,832,606 as shown on Schedule 21, Line 44.

Q. Does this conclude your testimony?

A. Yes, it does.

DECLARATION

I, Jee Kim, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 5, 2019 in Rosemead, California

Jee Kim

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

EXHIBIT SCE-14

EXHIBIT TO THE TESTIMONY OF MS. JEE KIM

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

PRELIMINARY STATEMENT Sheet 1

G. Gross Revenue Sharing Mechanism

The purpose of the Gross Revenue Sharing Mechanism (GRSM) is to record the customers' share of certain Other Operating Revenue (OOR) pursuant to Decision No. 99-09-070 (D.99-09-070).

In D.99-09-070 the Commission adopted, with clarifications, a Settlement Agreement between SCE and the Office of Ratepayer Advocates (ORA) for a gross revenue sharing mechanism associated with the SCE's non-tariffed products and services.

The gross revenue sharing mechanism adopted in D.99-09-070 applies to all of SCE's OOR, except revenue that is:

- Derived from tariffs, fees, or charges established by the Commission or Federal Energy Regulatory Commission;
- Subject to other established ratemaking procedures or mechanisms; or
- Subject to the Demand Side Management Balancing Account.

1. Definitions

   a. Active Sharing Allocation

   The Active Sharing Allocation is 90%/10% (shareholder/customer) for Incremental OOR associated with non-tariffed products and services deemed "active" by the Commission. The allocation shall apply over the life of the non-tariffed product or service offering and/or applicable contract.

   b. Incremental OOR

   Incremental OOR is the recorded gross revenue derived from non-tariffed products and services subject to the GRSM that exceeds the OOR Threshold during each calendar year. Incremental OOR is subject to the gross revenue sharing mechanism adopted in D.99-09-070, and shall be allocated between shareholders and customers using the Active Sharing Allocation or the Passive Sharing Allocation.

(Continued)

PRELIMINARY STATEMENT Sheet 2

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

1. Definitions (Continued)

c. OOR Threshold

The annual calendar year OOR Threshold is equivalent to the amount of OOR from non-tariffed products and services reflected as a revenue credit in SCE's most recent General Rate Case (GRC). The current OOR Threshold is $16,671,389 and is based upon the level of OOR from non-tariffed products and services reflected as a revenue credit in SCE's 1995 Test Year GRC (D.96-01-011). This amount shall remain fixed until SCE's next GRC or otherwise modified by the Commission. Recorded non-tariffed products and services gross revenues that is greater than the OOR Threshold during any calendar year is considered Incremental OOR and shall be allocated to SCE's shareholders and customers using the Active Sharing Allocation or the Passive Sharing Allocation.

d. Passive Sharing Allocation

The Passive Sharing Allocation is 70%/30% (shareholder/customer) for Incremental OOR associated with non-tariffed products and services deemed "passive" by the Commission. The allocation shall apply over the life of the non-tariffed product or service offering and/or applicable contract.

2. Operation of the Gross Revenue Sharing Tracking Account

SCE shall maintain a Gross Revenue Sharing Tracking Account (GRSTA). Entries to the GRSTA shall be made on a monthly basis and shall be determined as follows:

a. GRSTA entries when the annual calendar year OOR Threshold is not reached.

The following calculation shall commence on January 1st of each calendar year, and shall continue until the OOR Threshold is reached during the calendar year.

(1) Annual calendar year OOR Threshold;

(2) Less: Recorded calendar year-to-date gross revenues from non-tariffed products and services subject to the GRSM (as of the end of the applicable month);

(3) If the result of "2.a.(1)" and "2.a.(2)" above is a positive amount, there shall be no entries made to the GRSTA for the month.

(Continued)

PRELIMINARY STATEMENT Sheet 3

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

2. Operation of the GRSTA (Continued)

a. GRSTA entries when the annual calendar year OOR Threshold is not reached. (Continued)

(4) If the result of the calculation of “2.a.(1)” and “2.a.(2)” above is a negative amount, then the OOR Threshold has been reached and recorded Incremental OOR must be allocated between shareholders and customers. See 2.b. and 2.c. below.

b. GRSTA entries in the month that the OOR Threshold is reached.

(1) If the result of the calculation of “2.a.(1)” and “2.a.(2)” above is a negative amount, then the Incremental OOR for that month shall be shared between shareholders and customers using the Active Sharing Allocation and the Passive Sharing Allocation.

(2) In the month of each calendar year that the OOR Threshold has been reached, Incremental OOR shall be allocated between “active” and “passive” non-tariffed products and services based upon the proportion for each of the non-tariffed products and services gross revenues recorded during the month.

(3) The customers’ share of Incremental OOR shall be credited to the GRSTA by applying the Active Sharing Allocation and the Passive Sharing Allocation. The shareholder portion of Incremental OOR shall not be recorded in the GRSTA.

c. GRSTA entries in the months during the calendar year subsequent to the month in which the OOR Threshold is reached.

During these months of each calendar year all recorded non-tariffed products and services OOR subject to the GRSM shall be considered Incremental OOR for gross revenue sharing purposes.

(1) Recorded Incremental OOR for the month shall be allocated to shareholders and customers by applying the applicable Active Sharing Allocation or Passive Sharing Allocation to the recorded gross revenues from non-tariffed products and services subject to the GRSM.

(2) The customers’ share of the resultant allocations shall be credited to the GRSTA. The shareholder portion of Incremental OOR shall not be recorded in the GRSTA.

(Continued)

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

2. Operation of the GRSTA (Continued)

d. Monthly Interest

Interest shall accrue monthly in the GRSTA by applying the Interest Rate to the average of the beginning of month balance and the end of month balance.

e. Annual Calendar Year-End Transfers of the GRSTA

At the end of each calendar year SCE shall transfer the balance in the GRSTA (including accrued interest) to the Electric Deferred Refund Account (EDRA), or other ratemaking mechanism authorized by the Commission. On each January 1st the balance in the GRSTA shall be reset to zero subsequent to the transfer of the December 31st GRSTA balance.

3. Advice Letter Process

SCE may request a change in classification from “passive” to “active” for an existing non-tariffed product and service offering, as defined in Section F of the OOR Settlement Agreement (as authorized in D.99-09-070), by filing an advice letter with the Commission.

To reclassify a product or service offering as “active,” the advice letter must show that the product or service offering involves incremental shareholder investment of at least $225,000 (either on a one-time basis or within a twelve-month period).

SCE shall not file more than four such advice letters in any calendar year. Prior to filing any such advice letter, SCE shall meet with the ORA, or its successor organization, to discuss the planned advice letter and the proposed classification of the new product or service offering.

Advice letters requesting a reclassification of a product or service offering from “passive” to “active” shall be governed by General Order 96-A, or its successor.

(Continued)

PRELIMINARY STATEMENT Sheet 5

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Secondary Use of Transmission Right-of-Ways and Land	- Placement of third-party communications equipment, attachments, conduit and cable - Agricultural/Horticultural - Storage facilities - Parking lots - Vehicle storage - Film production site locations - Sale or trading of excess water rights - Sale or trading of mineral rights - Billboard Placements - Parks and Recreation - Stables	Passive	(N) | (N)
Secondary Use of Distribution Right-of-Ways, Land, Facilities and Substations	- Placement of third-party communications equipment, attachments, conduit and cable - Agricultural/Horticultural - Parking lots - Vehicle storage - Film production site locations - Sale or trading of excess water rights - Sale or trading of mineral rights - Billboard Placements - Parks and Recreation - Stables - Storage Facilities	Passive	(N) | | (N)
Secondary Use of SCE-Owned Generation Facilities and Land	- Placement of third-party communications equipment, attachments, conduit and cable - Agricultural/Horticultural - Film production site locations - Sale or trading of excess water rights - Sale or trading of mineral rights - Billboard Placements - Parks and Recreation - Stables - Vehicle Storage - Parking Lots	Passive	(N) | | | (N)

(Continued)

PRELIMINARY STATEMENT Sheet 6

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Secondary Use of Utility Owned Buildings and Offices	- Meetings/Conferences	Passive	(T)
	- Office space		(T)
	- Placement of third party communications equipment, attachments, conduit and cable		
	- Cafeteria and Vending Machines		(N)
Use of Transmission Towers, Distribution Poles, Facilities, Conduits, Ducts and Streetlight Poles	- Placement of third-party communications equipment, attachments, conduit and cable	Passive	
Use of Communications and Computing Systems	- Circuits, wave lengths and radio spectrum	Active	
	- Dark fiber on fiber optic system		
	- Cable pairs on copper communication cables		
	- Communications and computing capacity, installation, maintenance and support		
	- Fiber optic and other communications cable construction, equipment installation, and site development		
	- Marketing of third parties' right-of-ways, poles, towers and other facilities for communication-related purposes		
	- Infrastructure-related telecommunication services		(N)
	- Infrastructure-related computing services		|
	- Communication and computing service center services		(N)

(Continued)

PRELIMINARY STATEMENT — Sheet 7

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
License of Utility Software	- Utility developed software (e.g., Outage Management System, Fleet Management System) - Software licensed to Utility (e.g., energy usage tracking software)	Passive	
Licensing of Utility-Held Patents[1/]	- Licensing of Utility developed technologies such as the Insulator Washing Technology	Passive	(T)
Property Management, Property Maintenance and Real Property Brokerage Services	- Title searches - Brokerage activities - Property management - Janitorial and building maintenance	Passive	
Recreation, Fish and Wildlife Activities	- Campground rentals - Campground maintenance - Fish hatchery	Passive	
Sales of Timber Stands on Utility-Owned Property	- Timber sales	Passive	
Use of Customer Technology Application Center (CTAC) and Agricultural Technology Application Center (AgTAC) Facilities	- Conference facilities - Audiovisual services - Catering - Teleconferencing/downlinks - Technical seminars and training - Partnership training (e.g., with federal government) - Customer product/technology testing and demonstrations - Display space and display set-up - Display development and consulting	Passive	
Electric Vehicle (EV), Battery, and Charger-Related Services	- EV operational, performance, calibration and reliability testing - Battery performance, safety, power quality and reliability testing - Charger operational, performance, reliability, safety, power quality, efficiency and life cycle testing - Customer education and training on EV technologies, operations, charging safety, diagnosis and maintenance	Active	

1/ Does not include revenue sharing mechanism related to financial benefits of Intellectual Property that was developed under Electric Program Investment Charge (EPIC) funds in D.13-11-025. (N)
(N)

(Continued)

PRELIMINARY STATEMENT — Sheet 8

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Energy Efficiency Engineering Consulting and Technical Services	- Lighting surveys - Lighting systems bid specifications - Lighting systems construction observation - Building energy simulations - End-use consulting - Facilities engineering, analysis and commissioning - Submetering	Passive	

Billing and Customer Communication Center Services for Non-ESPs	- Bill Customization
	- Usage Calculation
	- Bill calculation
	- Bill presentation (e.g., mailing, summary billing, EDI billing, flexible bill routing)
	- Payment processing (e.g., mail, in-person through APA network etc.)
	- Credit and collections activities
	- Customer Communications Center Services for clients' customer calls. These services can be provided in seven languages and include, but are not limited to:
	  - requests for service connection (turn ons)
	  - transfer of service or turn offs
	  - customer credit inquiries
	  - customer extension/payment arrangements
	  - billing inquiries
	  - billing investigations
	  - outage reports
	  - account transfers
		Active	(D)

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Meter Reading and Field Services for Non-ESPs	- Meter reading (usage measurement) - Transfer of meter reading information - Special and mid-cycle meter reads - Physical and remote turn ons; turn offs - Physical and remote disconnects and reconnects - Meter change-outs - Other field services	Active	
Bill Payment Options	- Pay-by-phone - Pay-by-Internet - Direct Payment - Acceptance of payments for telecommunications providers in rural locations	Passive	(D)
Vehicle Maintenance and Repair	- Vehicle maintenance and repair - Comprehensive Fleet management	Passive	
Transportation and Disposal of Hazardous Materials	- Transportation and disposal of hazardous material such as waste by-product from generation	Active	
Use of Heavy Equipment and Machinery	- Use of heavy equipment such as cranes and rigging services, helicopters and other machinery or equipment	Passive	

PRELIMINARY STATEMENT — Sheet 10

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Operation and Maintenance, and Repair of Generation, Transmission and Distribution Related Facilities and Equipment	- Operation of power generation, transmission, and distribution equipment and facilities	Active	(L) (T)(N)(D) (N)
	- On-site Inspection, maintenance, troubleshooting, repair, replacement, and installation of distribution and transmission facilities (e.g., electrical apparatus, streetlights, conductors, towers, poles, transformers)		(T)(C) (C)
	- On-site inspection, maintenance, troubleshooting, and repair of protection systems, telecommunication cables and equipment (e.g., fiber optics and microwave		(N) (D) (N)
	- Metering, measurement and test equipment services (e.g., engineering, system analysis, meter installation, maintenance, testing, calibration, and repair)		(N) (D) (N)
	- Electrical and mechanical engineering and consulting services		(C) (C)
	- Precision dimensional measurement consulting and engineering		(N)(D) (N)
	- Nuclear decommissioning consulting and engineering		(N)(D) (N)
Advanced Testing of Hydraulic Pumps	- Advanced testing of hydraulic pump and associated electrical equipment	Passive	(L) (L)

(Continued)

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
			(L)
Equipment and Machinery Repair, Testing, Maintenance and Calibration	- Shop service repairs of mechanical and electrical apparatus and equipment such as valves, motors, turbines, transformers, and generators - Material testing - Instrumentation repair and calibration - Metering, measurement and test equipment services (e.g., engineering, system analysis, meter installation, maintenance, testing, calibration, and repair) - Electrical and mechanical engineering and consulting and engineering - Training - Precision dimensional measurement consulting and engineering - Nuclear decommissioning consulting and engineering	Active	(T) (T) (N) (D) | | | (N)
			(D)
Geographic Information Systems (GIS) Services	- Mapping services - Map creation - Specialized geographic data base analysis and development - User training	Passive	
			(D)
Tariff Sheet Sales	- Tariff sheet sales	Passive	(N)
Recycling Services	- Paper Recycling - Trash Recycling	Passive	|
Training and Technical Certification Services	- Training, technical certification, conferences, and seminars	Passive	| (N)
Material Procurement and Purchasing Services	- Aggregated procurement and purchasing services of machinery, materials, equipment, tools, parts, office equipment, and supplies	Passive	(L) |
Fuel Oil Pipeline System and Storage Facilities	- Fuel oil transportation services - Fuel oil storage services	Not subject to proposed revenue sharing mechanism	| (L)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF ANTONIO OCEGUEDA

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-15)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
ANTONIO OCEGUEDA

(EXHIBIT SCE-15)

Mr. Ocegueda provides an overview of Plant Held for Future Use under Schedule 11, Abandoned Plant under Schedule 12, Network Upgrade Credits under Schedule 22, Regulatory Assets/Liabilities under Schedule 23, and the Transmission Wages and Salary Allocation Factor and the Transmission Plant Allocation Factor calculated under Schedule 27.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	)))	**Dkt. No. ER19-______-000**

PREPARED DIRECT TESTIMONY OF
ANTONIO OCEGUEDA
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Antonio Ocegueda, and my business address is 8631 Rush St, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Senior Advisor in the FERC Rates and Market Integration Division of the Regulatory Affairs Department. My primary responsibilities include developing rates for services that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Mechanical Engineering from Loyola Marymount University in May 1999. I received a Master of Planning degree from the University of Southern California in May 2003. In December 2003, I joined SCE as a Contract Manager in the Regulatory Policy and Contracts Division within the Transmission and Distribution Department, where my responsibilities included management of FERC-jurisdictional transmission and distribution agreements. In January 2006, I transferred to my current position in what was then the Regulatory Operations Department.

Q. Have you submitted testimony to the Commission previously?

A. Yes. I have submitted testimony in SCE's prior updates to the Transmission Access Charge Balancing Account Adjustment under Docket Nos. ER15-1399, ER16-1272, and ER17-1345. I also submitted testimony in SCE's update to its Reliability Services Balancing Account under Docket Nos. ER15-216, ER17-232, ER18-184, and ER19-219. Finally, I submitted testimony in SCE's transmission rate case proceedings under Docket Nos. ER08-1343, ER09-1534, ER11-3697, and ER18-169.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Plant Held for Future Use under Schedule 11, Abandoned Plant under Schedule 12, Network Upgrade Credits under Schedule 22, Regulatory Assets/Liabilities under Schedule 23, and the Transmission Wages and salary Allocation Factor and the Transmission Plant Allocation Factor calculated under Schedule 27 of SCE's proposed Formula Rate.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedules 11 (Plant Held for Future Use), 12 (Abandoned Plant), 22 (Network Upgrade Credits), 23 (Regulatory Assets), and a portion of Schedule 27 relating to the Wages and Salaries Allocation Factor and Plant Allocation Factor (Lines 1-22).

II. TRANSMISSION PLANT HELD FOR FUTURE USE

Q. Please describe how Transmission Plant Held for Future Use is handled under Schedule 11 of the proposed Formula Rate.

A. Transmission Plant Held for Future Use ("PHFU") is typically comprised of two categories of costs. First, it includes land or land rights purchased in advance of transmission plant construction that is intended to be placed under the Operational Control of the California Independent System Operator Corporation ("CAISO" or "ISO"). Second, PHFU includes any General Plant Held for Future Use. This category of costs is allocated to the ISO based on a labor allocator that I explain in more detail below. Schedule 11 of the proposed Formula Rate reports all categories of PHFU included in ISO rate base. Additionally, Schedule 11 reports any gains or losses related to the sale of land that is part of PHFU. This is consistent with Commission policy that requires gains or losses on the land component of Transmission Plant Held for Future Use to be flowed back to ratepayers. However, gains or losses on non-land Transmission Plant Held for Future Use are not required to be flowed back to ratepayers.

Q. Are there any changes to the treatment of PHFU under the proposed Formula Rate relative to the currently effective Formula Rate for SCE ("Second Formula Rate")?

A. No.

Q. What amount of PHFU is reflected in the proposed Formula Rate 2017 Prior Year TRR, and included in the proposed 2019 Base TRR?

A. For the proposed Formula Rate 2019 Base TRR, the PHFU amount included in the Prior Year TRR for 2017 is $9,942,155 (See Exhibit No. SCE-4, Schedule 11, Line 2a). This amount is related to land purchased for SCE's proposed Alberhill System Project. There is no General Plant Held for Future Use in 2017 reflected in PHFU.

III. ABANDONED PLANT

Q. Please describe how Abandoned Plant is handled in the Proposed Formula Rate.

A. As discussed by Mr. Hansen (Exhibit SCE-3), Abandoned Plant Amortization Expense is included in Schedule 12 of Exhibit No. SCE-4 with respect to projects for which SCE has received a Commission Order approving recovery of prudently incurred costs for projects that are abandoned due to factors beyond SCE's control. Costs are recovered through the approved annual amortization of the abandoned plant costs. Unamortized Abandoned Plant costs may also be included in Rate Base through the Abandoned Plant component of Rate Base. The authorized recovery of abandoned plant for each particular project serves as the inputs to Schedule 12.

Q. Are there any changes to the treatment of Abandoned Plant under the proposed Formula Rate relative to the Second Formula Rate?

A. No.

Q. Please describe the Abandoned Plant inputs under Schedule 12.

A. For each project that has been granted Abandoned Plant treatment by the Commission, Schedule 12 outlines the Abandoned Plant Amortization Expense. This value is consistent with any amount of Abandoned Plant that the Commission has authorized SCE to expense in the Prior Year. Lines 7-17 summarize the Commission approved Abandoned Plant Amortization Expense schedule for a particular project. Schedule 12 also reports the beginning and end of year Abandoned Plant balances (Lines 2 and 3), which serve to compute the Abandoned Plant component of Rate Base.

Q. What is the authorized Abandoned Plant for the 2017 Prior Year reflected in the proposed Formula Rate and included in the proposed 2019 Base TRR?

A. For the proposed Formula Rate Base TRR for 2019, Schedule 12 reflects no authorized Abandoned Plant. This is because SCE did not seek Abandoned Plant recovery for any project applicable to 2017.

IV. NETWORK UPGRADE CREDITS

Q. Please describe Network Upgrade Credits payable to generators.

A. Over the last several years, SCE has entered into numerous agreements for interconnecting new generation projects. Pursuant to these agreements, SCE has collected up-front payments from generators to fund the construction of upgrades to ISO transmission facilities owned by SCE ("Network Upgrades"). Such up-front payments are generally made up of a payment towards work that will be capitalized ("Facility Payment"), and in some cases, a payment towards non-capitalized work ("One-Time Payment"). Under current FERC policy, the up-front payments made by a generator associated with Network Upgrades are subject to refund to the generator with interest. The Network Upgrade Credit is the balance of the monies collected from generators less amount refunded. The Network Upgrade Credit is a reduction to rate base.

Q. Are there any changes to the treatment of Network Upgrade Credits under the proposed Formula Rate relative to the Second Formula Rate?

A. No.

Q. Please describe how Network Upgrade Credits are paid.

A. Network Upgrades are initially financed by the interconnecting generator via upfront payments to SCE. Generally, Network Upgrade Credits are then paid to the interconnection generator over a five-year period, in quarterly installments, beginning on the in-service date of the Network Upgrades.

Q. Please describe how the interest paid to the generators for Network Upgrades is calculated.

A. Interest accrues beginning on the date SCE receives the upfront payments from the interconnecting generator. Such interest is broken down into two periods: (i) the period prior to the in-service date ("Pre-In-Service Interest"); and (ii) the period after the in-service date ("Post-In-Service Interest"). This interest is calculated in accordance with the Commission's regulations, 18 CFR § 35.19a(a).

Q. Please describe the adjustment to the Base TRR for Network Upgrade Credits.

A. To assure recovery of the Network Upgrade Credits and the associated interest expense, SCE makes two adjustments to the calculation of its Base TRR and True Up TRR. First, SCE reduces its ISO rate base with the un-refunded balance of the up-front Facility Payments associated with the Network Upgrades that are included in rate base. This rate base reduction is shown on Schedule 1, Line 17 and Schedule 4, Line 15. The rate base reduction is calculated in Schedule 22. The second adjustment is the addition of an expense item reflecting the interest expense associated with Network Upgrade Credits that SCE paid to generators during the Prior Year. SCE treats these Network Upgrades associated with generator interconnections as any other Network Upgrade. Consequently, SCE reflects the cost of the Network Upgrade in rate base, and accrues Allowance for Funds Used During Construction on the Network Upgrades during construction (with the exception of projects that have been granted Construction Work in Progress recovery). In determining the interest expense to reflect in the Base TRR and True Up TRR, with one exception described below, SCE has excluded any interest costs accrued during construction associated with payments made by the generator (i.e. the Pre-In-Service Interest).

Q. Please describe the "one exception" you refer to above.

A. For One-Time Payments, both the Pre-In-Service and Post-In-Service Interest are included in the transmission cost of service. While Network Upgrades are included in rate base, work associated with One-Time Payments is not. In order for SCE to be left whole, the Pre-In-Service Interest for One-Time Payments must be, and has been, included in the transmission cost of service. This interest expense is shown on Schedule 1, Line 68 and Schedule 4, Line 29, and is calculated in Schedule 22.

Q. Please summarize the results of your proposal.

A. The rate base adjustment flows through to the ISO ratepayers the benefit associated with the up-front payments used to finance the construction of these Network Upgrades. The second adjustment flows through the costs associated with this source of financing to ISO ratepayers. These two adjustments work together to insure that ISO ratepayers receive the benefit of generator up-front payments, while remaining ultimately responsible for the costs of such Network Upgrades. This is the same approach as SCE has used in its Second Formula Rate.

Q. What amount of Network Upgrade Credits is included in the 2017 Prior Year TRR for the proposed 2019 Base TRR?

A. SCE is including a credit to Rate Base of $93,345,105 in the 2017 Prior Year TRR, as shown in Exhibit No. SCE-4, Schedule 22, Line 4.

V. REGULATORY ASSETS/LIABILITIES

Q. Please describe how Regulatory Assets/Liabilities are handled under Schedule 23 of the formula rate.

A. As discussed by Mr. Hansen, the purpose of this cost category is to provide a mechanism for any regulatory assets/liabilities created by ratemaking actions of regulatory agencies to be recovered through transmission rates. All Commission approved regulatory assets and liabilities are summarized in Schedule 23 of the proposed Formula Rate.

Q. Are there any changes to the treatment of Regulatory Assets/Liabilities under the proposed Formula Rate relative to the Second Formula Rate?

A. No.

Q. Please describe the regulatory asset/liability inputs under Schedule 23.

A. Schedule 23 lists the Commission approved asset/liability, approval order reference, the beginning and end of year balance, as well as the amortization amount authorized in the Prior Year.

Q. Are there any exceptions to what assets/liabilities are reported under Schedule 23?

A. Yes. Schedule 23 excludes any Abandoned Plant costs recovered under Schedule 12.

Q. What are the regulatory asset/liability inputs for 2017 reflected in the proposed Formula Rate?

A. For the proposed Formula Rate, there are no regulatory assets/liabilities to be reported under Schedule 23 for 2017.

VI. TRANSMISSION WAGES AND SALARY ALLOCATION FACTOR

Q. Please describe the Transmission Wages and Salary Allocation Factor.

A. The Transmission Wages and Salaries Allocation Factor ("Labor Allocator") is a labor ratio derived by dividing ISO Transmission Wages and Salaries by total Wages and Salaries. This calculation is exclusive of A&G related Wages and Salaries. The Labor Allocator is used in the proposed Formula Rate to allocate certain costs to ISO ratepayers.

Q. Are there any changes to the treatment of the Labor Allocator under the proposed Formula Rate relative to the Second Formula Rate?

A. No.

Q. Please describe how the ISO Transmission Wages and Salary is calculated.

A. ISO Transmission Wages and Salary is derived from Schedule 19 – Operations and Maintenance. This schedule determines the total transmission and distribution labor that is attributable to ISO. Schedule 19 is described in more detail in the testimony of Mr. Moon, Exhibit No. SCE-9. This value is the numerator of the Labor Allocator.

Q. Please describe how total Wages and Salary is calculated.

A. This calculation begins with total Wages and Salary as reported in FERC Form 1. Second, A&G related Wages and Salaries, also as reported in FERC Form 1, is subtracted. Third, NOIC, except NOIC associated with A&G, is added to the total since this type of expense is not reported as Wages and Salaries in FERC Form 1. The final result is total non-A&G Wages and Salaries, inclusive of NOIC. This value is the denominator of the Labor Allocator.

Q. What is the Labor Allocator for 2017 under the proposed Formula Rate?

A. For the proposed Formula Rate, the 2017 Labor Allocator is 6.0143%. The detail calculation is shown on Lines 1-9 of Schedule 27.

VII. TRANSMISSION PLANT ALLOCATION FACTOR

Q. Please describe the Transmission Plant Allocation Factor.

A. The Transmission Plant Allocation Factor ("Plant Allocator") is a plant ratio derived by dividing Total Plant In Service attributable to ISO by Total Plant In Service. The Plant Allocator is used in the proposed Formula Rate to allocate certain costs to ISO ratepayers.

Q. Are there any changes to the treatment of the Plant Allocator under the proposed Formula Rate relative to the Second Formula Rate?

A. No.

Q. Please describe how Total Plant In Service attributable to ISO is calculated.

A. Total Plant In Service attributable to ISO is equal to the sum of four components, (1) Transmission Plant – ISO, (2) Distribution Plant – ISO, (3) Electric Miscellaneous Intangible Plant – ISO, and (4) General Plant – ISO.

Q. Please describe how Transmission Plant – ISO is calculated.

A. Transmission Plant – ISO is derived from Schedule 7 – Transmission Plant Study Summary. This schedule summarizes the results of SCE's Plant Study and presents the total transmission plant that is attributable to ISO. SCE's Plant Study and Schedule 7 of Exhibit No. SCE-4 are described in more detail in the testimony of Mr. Moon, Exhibit No. SCE-9.

Q. **Please describe how Distribution Plant – ISO is calculated.**

A. Like Transmission Plant ISO, Distribution Plant – ISO is derived from Schedule 7 – Transmission Plant Study Summary. Note that currently there are no distribution plant assets attributable to ISO.

Q. **Please describe how Electric Miscellaneous Intangible Plant – ISO is calculated.**

A. Electric Miscellaneous Intangible Plant ISO ("ISO Intangible Plant") is derived by multiplying Total Electric Miscellaneous Intangible Plant ("Intangible Plant") by the Labor Allocator. Intangible Plant is derived from Schedule 6 – Plant In Service. Among other things, this schedule summarizes the end of year Intangible Plant balance. Schedule 6 is described in more detail in the testimony of Mr. Gunn, Exhibit No. SCE-7.

Q. **Please describe how General Plant – ISO is calculated.**

A. General Plant - ISO is derived by multiplying Total General Plant by the Labor Allocator. General Plant is derived from Schedule 6 – Plant In Service. Among other things, this schedule summarizes the end of year Total General Plant balance. Schedule 6 is described in more detail in the testimony of Mr. Gunn, Exhibit No. SCE-7.

Q. **Please describe how Total Plant In Service is determined.**

A. The Total Plant In Service value is as reported in FERC Form 1.

Q. **What is the Plant Allocator for 2017 under the proposed Formula Rate?**

A. For the proposed Formula Rate, the Plant Allocator is 19.1484%. The detail calculation is shown on Lines 14-22 of Schedule 27 of Exhibit No. SCE-4.

Q. **Does this conclude your testimony?**

A. Yes, it does.

DECLARATION

I, Antonio Ocegueda, , identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 5, 2019 in Rosemead, California

Antonio Ocegueda

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF ROBERT A. THOMAS

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-16)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
ROBERT A. THOMAS

(EXHIBIT SCE-16)

Mr. Thomas discusses the methods used to develop the Retail Level transmission rates, as performed in Schedule 33 of SCE's proposed Formula Rate Spreadsheet. The testimony includes a discussion on the development and application of the 12 months of coincident peak (12-CP) allocation factors for Retail Base TRR revenue allocation, followed by a discussion on the billing determinants and rate design. Customers with on-site generation resources are served on standby rates, which are reflected in their respective retail rate groups for purposes of revenue allocation and rate setting. Mr. Thomas also provides factors to use in the True Up Adjustment in the event a partial year true up is necessary. Finally, Mr. Thomas supports the retail aspects of cost of Service Statements BG, BH, and BL.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
ROBERT A. THOMAS
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Robert A. Thomas, and my business address is 8631 Rush Street, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am the Manager of Rate Design in the Regulatory Affairs Organization at Southern California Edison Company. In this position, I am responsible for the development of SCE's retail level rate designs. I have held this position since November 20, 2006.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor's of Science and Engineering from the University of Arizona, a Professional Engineer License in Mechanical Engineering, and a Masters in Business Administration from California State Polytechnic University, Pomona. Prior to my present position, my responsibilities have included Manager of the Analysis and Program Support Group, within SCE's Business Customer Division, where I was responsible for providing customer specific rate and financial analyses involving self-generation, load growth, contract rates, and hourly pricing options. Prior to this position, I was SCE's

Program Manager for the Self Generation Incentive Program ("SGIP"). In this position I was responsible for all aspects of the program including processing of applications, promotion of the program, and dispute resolution. I was also SCE's lead representative on the SGIP Working Group.

Q. Have you submitted testimony to the Commission previously?

A. Yes. I have submitted testimony in SCE's 2012, 2013, 2014, 2015, 2016, and 2017 Reliability Services filings (Docket Nos. ER12-201, ER13-227, ER14-222, ER15-216, ER16-174, and ER17-232), and in SCE's TO4, TO5, and TO6 transmission rate case proceedings (Docket Nos. ER08-1343, ER09-1534, and ER11-3697). I also submitted testimony in SCE's Formula Rate Revisions (Docket Nos. ER16-1292-000, ER16-1393-000, ER18-169-000, and ER19-374-000).

I. <u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe SCE's proposed formula for designing retail rates to recover the Base Transmission Revenue Requirement ("Base TRR") as set forth in Schedule 33 of the proposed Formula Rate Spreadsheet, (Exhibit SCE-4). My testimony will address:

- The formula methodology for allocating the Base TRR to retail rate groups based on each group's load contribution to the system coincident peak demand over 12 months ("12 months of coincident peak" or "12-CP");
- Determination of the component level rate factors (i.e., demand and energy charges) for each rate schedule based on the 12-CP revenue allocations;
- The Formula Rate treatment of standby and station load customers in the development of proposed retail transmission rates for these customer groups and;

- The retail aspects of SCE's Statements BG, BH, and BL.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 33 (Retail Rates).

II. OVERVIEW OF SCE'S RETAIL RATE CALCULATION METHODOLOGY

Q. How does the proposed Formula Rate determine the retail transmission rates?

A. Retail rates are developed in Schedule 33 of the proposed Formula Rate Spreadsheet (Exhibit SCE-4). Schedule 33 determines the retail transmission rates by first allocating the Retail Base TRR to retail rate groups based on each group's percentage contribution to the system 12-CP. The retail rate groups are those approved by the California Public Utilities Commission ("CPUC") and will be input into the Schedule 33 when it is updated each year in the Annual Update. Retail transmission rates are then determined for each rate group by applying forecasted billing determinants. Schedule 33 uses the sum of forecast monthly maximum demands (kW) for demand metered customers; forecast annual energy (kWh) usage for non-demand metered customers; and the sum of monthly recorded standby kW demands for standby customers with on-site generation.

Q. Please describe the design methodology for determining the 12-CP allocation factors.

A. The proposed Formula Rate uses the 12-CP methodology to allocate the Base TRR across the retail rate groups. To develop the 12-CP rate group level allocation factors, Schedule 33 averages the most recently available 3-year load research data to calculate the 12 months of coincident peak demand for each rate group. The resulting 3-year average of the 12 monthly coincident peak demand, by retail rate group is then adjusted for distribution losses to derive 12-CP data for each rate group at the meter level. The loss adjusted

12-CP data are further adjusted to account for forecasted sales. This additional step minimizes the impact associated with large customer migrations between rate groups. The 12-CP percent allocation factors, by retail rate groups are then determined by dividing each rate group's proportional contribution to the loss adjusted 3-year average system peak demands. This calculation is performed in Schedule 33 on Lines 35a through 36, Columns 1 through 11 of Exhibit SCE-4. The current 12-CP allocation was initially presented in TO-2019.

Q. Please describe the design methodology for determining the revenue allocation by retail rate group.

A. To perform the Base TRR revenue allocation, the 12-CP allocation percentages, by retail rate group are then multiplied by the Retail Base TRR to determine each rate group's transmission cost responsibility for rate design purposes. This revenue allocation process is consistent with the current Base TRR allocation method. The calculation is performed in Schedule 33 on Line 1a through 2, Columns 1 through 2 of Exhibit SCE-4.

Q. Please describe the rate design methodology used to develop retail rate levels.

A. The proposed Formula Rate determines retail rates for each Rate Schedule using allocated Retail Base TRR costs, as described above, applied to the specific forecast billing determinants of each rate group. Monthly retail transmission charges are established by dividing allocated costs by the sum of the forecasted monthly billing determinants for the respective rate groups. For the demand metered customers with monthly demand greater than 500 kW where SCE regularly serves their loads, the formula develops a monthly transmission demand rate using the maximum non-time related demands (kW) for the billing cycle (Schedule 33, Lines 9a through 9d, Columns 5 through 8 of Exhibit SCE-4). For energy-only rate groups, where SCE only meters kWh energy consumption, monthly transmission energy charges are developed by dividing the allocated Retail Base TRR by the annual forecasted kWh to produce a $/kWh charge (Schedule 33, Lines 16a through 17, Column 5 of Exhibit SCE-4). The energy only rate groups include the Domestic, GS-1, TC-1, and Street & Area Light rate groups. For customers receiving standby service in demand-metered rate groups, the formula develops retail transmission rates using the monthly recorded standby kW demands for the billing cycle (Schedule 33, Lines 9a through 9d, Columns 1 through 3 of Exhibit SCE-4). For customers with monthly demand less than 500 kW, the formula develops a monthly transmission demand rates using the maximum non-time related kW demands and standby kW demands for the billing cycle (Schedule 33, Lines 16a through 17, Columns 1 through 10 of Exhibit SCE-4). In Docket No. ER19-374-000, submitted on November 20, 2018, SCE requested to add three new voluntary and optional electric vehicle (EV) rate schedules, associated with six CPUC rate groups, under schedule 33 of its formula rate. On January 10, 2019, the Commission issued a Letter Order in Docket No. ER19-374 accepting SCE's request. The change is incorporated in the calculations of the formula rate in Schedule 33 on lines 16a through 17, column 11 of Exhibit SCE-4. Additionally, on February 28, 2019 in Docket No. ER19-1149, SCE submitted proposed revisions to the Rate Schedules listed in Schedule 33, Lines 26a to 26o, to reflect the CPUC's Phase 2 Order, and to revise the names of some Rate Groups. This filing is currently pending before the Commission, and is reflected in this filing (both in the clean Formula Rate Spreadsheet Tariff and in the populated spreadsheet, Exhibit SCE-4).

III. <u>DERIVATION OF SCE'S BILLING DETERMINANTS USED IN CALCULATING RETAIL TRANSMISSION RATES</u>

Q. What are SCE's forecasted sales levels used in this filing to calculate retail rates?

A. SCE's retail sales at the meter level are 81,970 GWh, as reflected by the sum of the GWh on Line 2, Columns 3 and 4. This is based on SCE's latest corporate approved forecast filed in SCE's ERRA proceeding at the CPUC.

Q. How does SCE derive forecast billing determinants consistent with the aggregate retail sales forecast?

A. SCE first forecasts the number of customers and sales by revenue class, i.e., residential, commercial, industrial, agricultural and other public authorities. These broad classifications tend to be stable over time, and general economic and demographic data for them are commonly available. A normalized forecast of billing determinants by rate group, which matches the revenue class sales forecast in total, is then developed. The reason billing determinants are not forecast independently of the revenue class sales is that rate groups are not as stable as revenue classes, as customers tend to switch rate groups over time, and statistical analyses that capture general economic trends, such as expansions and recessions, are difficult to perform on rate group data without the demographic and economic data commonly available by revenue class.

Q. Are there any other aspects of the Formula Rate Spreadsheet that you are supporting?

A. Yes. There is one additional aspect of the proposed Formula Rate that I have provided. The proposed Formula Rate includes "Partial Year TRR Attribution Allocation Factors" to be used in the True Up Adjustment calculation in the event that a partial year True Up Adjustment must be performed. These are 12 monthly factors that sum to 100% which represent SCE's normal base transmission revenue recovery pattern over the 12 months of the year. The factors represent a three year average of monthly recorded retail base transmission revenue streams. They are shown in Schedule 3 of the proposed Formula Rate Spreadsheet, Lines 37-52, in Exhibit SCE-4. Mr. Hansen explains how these TRR Attribution Allocation Factors would be used in Exhibit SCE-3.

IV. COST OF SERVICE STATEMENTS

Q. Are you supporting any cost of service statements?

A. Yes, I am supporting the retail aspects of Statements BG (revenues at proposed rates), BH (revenues at present rates), and BL (proposed rates). Mr. Hansen in Exhibit SCE-3 supports the wholesale aspects of these three cost of service statements.

Q. How do you determine the retail information provided in Statements BG and BH?

A. For Statement BG (revenues at proposed rates), I apply SCE's proposed January 1, 2018 retail transmission rates, as stated in Exhibit SCE-4, to the forecast billing determinants used to calculate the transmission rates, on a monthly basis. For Statement BH (revenues at present rates), I apply SCE's present base retail transmission rates to these same forecast monthly billing determinants for 2018.

Q. Does this conclude your testimony?

A. Yes, it does.

DECLARATION

I, Robert A. Thomas, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 5, 2019 in Rosemead, California

Robert A. Thomas

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF SERGIO DEANA

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-17)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
SERGIO DEANA

(EXHIBIT SCE-17)

Mr. Sergio Deana's testimony supports Schedule 5 and portions of Schedule 1 of Southern California Edison's ("SCE") proposed formula rate, which determines the components of the capital structure, including associated costs of debt and preferred stock that are incorporated in the transmission revenue requirement.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF SERGIO DEANA ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Sergio Deana, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am the Principal Manager of Financial Planning and Regulatory Finance in the Treasurer's Department. My present responsibilities are to oversee financial projections and analyses for internal corporate purposes and regulatory filings.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Mechanical Engineering from Worcester Polytechnic Institute in 2001, a Master of Science degree in Mechanical Engineering from Rensselaer Polytechnic Institute in 2004, and a Master of Business Administration degree from Northwestern University in 2007.

I joined Southern California Edison in 2010 as a Project Manager in the Business Planning and Financial Management team within the Transmission &

Distribution business unit. In 2013 I was promoted to Senior Manager within SCE's Treasury Department, overseeing cash and capitalization forecasts in the Financial Planning & Analysis team, and in 2016 I was promoted to my current position of Principal Manager. Prior to joining Southern California Edison, I was an engineer, supervisor and manager in the aerospace and industrial supply industries.

Q. Have you submitted testimony to the Commission previously?

A. No.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I describe and calculate the capitalization used in the SCE's Formula rate. In particular, I detail the related calculations used in Schedule 5 to calculate both amounts and costs of Long Term Debt, Preferred Stock and Common Stock. These results are utilized in Schedule 1 to calculate the Cost of Capital Rate as well as other items.

Q. Can you please provide a summary of your testimony?

A. SCE's capitalization results in a Long Term Debt Capital Percentage of 42.1%, Preferred Stock Capital Percentage of 8.7%, Common Stock Capital Percentage of 49.2%. This results in a Cost of Capital Rate of 11.20%.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring the portion of Schedule 1 relating to return and capitalization calculations (Lines 37-56, except Line 50 "Return on Common Equity") and Schedule 5 (including parts ROR-1, ROR-2, ROR-3, and ROR-4 all relating to capital cost calculations).

II. THE RETURN ON CAPITAL

Q. What are the elements of the return on capital?

A. The return on capital includes the proportions of long-term debt, preferred equity, and common equity that finance SCE's rate base, also known as the capital structure, plus the costs of long-term debt, preferred equity, and common equity. The capital structure is based on recorded FERC Form 1 debt and preferred equity balances and associated recorded FERC Form 1 data with certain adjustments that I describe below. The costs of long-term debt and preferred equity are determined based on recorded FERC Form 1 data and SCE's internal records, using the methods prescribed for Statement AV in the Commission's regulations, with minor adjustments as described below to ensure recovery of all costs. The cost of common equity is determined in the formula based on SCE's annual percentage cost of equity, developed as discussed below, applied to SCE's recorded amount of common equity from FERC Form 1.

Q. How are the percentages of long-term debt, preferred equity, and common equity determined in the formula?

A. The percentages are based on 13-month averages for SCE's long-term debt, preferred equity, and common equity of the Prior Year.[1]

Q. How do you calculate the cost of long term debt?

A. The cost of long term debt is calculated consistent with the instruction in Statement AV, which states, "The utility shall show the following for each

1 The Prior Year is the most recent calendar year at the time an annual Informational Filing is submitted to the Commission. For a complete explanation of the Prior Year, please see Mr. Hansen's testimony in Exhibit SCE-3.

class and series of long term debt outstanding as of the end of Period I, as expected on the date the changed rate is filed, and, if applicable, as estimated to be outstanding as of the end of Period II.

"(1) Title;

"(2) Date of offering and date of maturity;

"(3) Interest rate;

"(4) Principal amount of issue;

"(5) Net proceeds to the utility;

"(6) Cost of money, which is the yield to maturity at issuance based on the interest rate and net proceeds to the utility determined by reference to any generally accepted table of bond yields;

"(7) Principal amount outstanding;

"(8) Name and relationship of issuer and if the debt issue was issued by an affiliate; and

"(9) If the utility has acquired at a discount or premium some part of the outstanding debt which could be used in meeting sinking fund requirements, or for some other reason, the annual amortization of the discount or premium for each issue of debt from the date of the reacquisition over the remaining life of the debt being retired. The utility shall show separately the total discount and premium to be amortized, and the amortized amount applicable to Period I and, if applicable, Period II."[2]

Q. How do you calculate the cost of preferred stock?

A. The cost of preferred stock is calculated consistent with the instruction in Statement AV, which states, "the statement shall show for each class and issue

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2 FERC Statement AV, pp. 267-268.

of hybrid and preference stock outstanding as of the end of Period I, as expected on the date the changed rate is filed, and, if applicable, as estimated to be outstanding as of the end of Period II:

"(1) Title;

"(2) Date of offering;

"(3) If callable, call price;

"(4) If convertible, terms of conversion;

"(5) Dividend rate;

"(6) Par or stated amount of issue;

"(7) Net proceeds to the filing utility;

"(8) Ratio of net proceeds to gross proceeds received by the filing utility;

"(9) Cost of money (dividend rate divided by the ratio of net proceeds to gross proceeds for each issue);

"(10) Par or stated amount outstanding; and

"(11) If issue is owned by an affiliate, name and relationship of owner."[3]

Q. Where is the calculation for cost of long term debt and cost of preferred stock shown?

The cost of long term debt is shown in Schedule 5-ROR-3. The cost of preferred stock is shown in Schedule 5-ROR-4.

Q. Is the calculation of cost of long term debt and cost of preferred stock consistent with the method used in the Second Formula Rate?

A. Yes, the calculation of the cost of long term debt and preferred stock is consistent with the method used in the Second Formula Rate. However, rather than using inputs from SCE internal records as was the case in the Second

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3 FERC Statement AV, pp. 268-269.

Formula Rate, the calculations now rely on inputs from FERC Form 1 data where available.

Q. Is the calculation method to determine the amount of long term debt and preferred stock consistent with previous filings?

A. Yes, the calculation method to determine the amount of long term debt and preferred stock is the same as previous filings. The amount of long term debt is calculated by using the bond balance in Account 221 plus several adjustments explained below. The amount of preferred stock is calculated by using the preferred stock amount in Account 204 plus several adjustments explained below.

Q. What adjustments are included in your calculations of these amounts?

A. The adjustments recognize two important facts: (1) SCE long-term debt issues, or identified portions of a debt issue that do not finance rate base should not be included in the calculation of long-term debt; and (2) rate base can only be financed with the net proceeds of SCE's financing activities, so that the amounts of long-term debt and preferred equity that are included in the calculation of the capital structure are less than the amounts of long-term debt and preferred equity that are outstanding and recorded in SCE's FERC Form 1.

Q. What SCE long-term debt does not finance rate base?

A. Series 2014C does not finance rate base.

Series 2014C bonds were issued for the purpose of financing SCE's fuel inventories.[4] SCE's fuel inventories are not part of SCE's Commission-

4 The Series 2014C bonds were issued pursuant to authority granted by the CPUC in D.14-02-021. The decision permits SCE to issue one or more series of debt securities and states in part: "Use the proceeds from the Debt Securities for the following purposes only: (i) pay accrued interest

jurisdictional rate base, and SCE is not permitted to use the proceeds from these bonds to finance operating expenses or capital additions. Therefore, the Series 2014C bonds should be excluded from any capital structure calculation in the formula. Interest costs and amortizations associated with these bonds are also excluded from any formula calculations.

Therefore, the Series 2014C bonds should be excluded from any capital structure calculation in the formula. Interest costs and amortizations associated with these bonds are also excluded from any formula calculations.

Due to the unique wildfire risk that SCE faces in light of inverse condemnation policies as described by Mr. Graves in Exhibits SCE – 22 & 24, SCE may find it necessary to issue debt in the future to specifically pay for wildfire related liability. Such debt, or specified portions thereof, would not finance rate base and thus would not be included in the calculation of the capital structure.

Q. Is debt associated with the SONGs regulatory asset still excluded?

A. No. Since the filing of the Second Formula Rate the status of SONGs debt changed as a result of a settlement.[5] The entire bond Series 2015AB, the debt that was issued to finance the SONGS regulatory asset, are now included in the calculation of amount and cost of long-term debt.

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and expenses incident to the issuance of the Debt Securities; (ii) finance diesel, natural gas, and nuclear fuel inventories; (iii) retire or refund $400 million of debt securities issued previously to finance fuel inventories pursuant to Decision 03-11-018; and (iv) reimburse SCE for money it has expended from its income, or from funds in its treasury that are not secured or obtained from the issuance of debt or equity, for the aforesaid purposes except maintenance of service and replacements. The amounts so reimbursed shall become a part of SCE's general treasury funds." D.14-02-021 Ordering Paragraph 1b.

5 *Decision on the January 30, 2018 Joint Motion for Adoption of Settlement Agreement*, 2018 WL 3753857 (CPUC July 26, 2018).

Q. When do the 2014C bonds mature?

A. Series 2014C matured in November 2017 and has a standard structure with a balloon payment at maturity.

Q. Please explain your comment that rate base can only be financed with the net proceeds of SCE's financing activities.

A. Issuing long-term debt and preferred equity causes SCE to incur three types of costs: discounts or premiums, expenses, and (in some cases) losses on reacquired debt or preferred equity. These costs are not recovered through operations and maintenance expense, instead they are amortized over the life of the associated security. The amount that is available to finance rate base is the face value of the security *less* the unamortized amount of these costs.

Q. Why must one take account of unamortized expenses, discounts/premiums, and losses on reacquired securities to correctly calculate the amount of debt and preferred equity in the capital structure?

A. If one does not take account of these items, then the utility, SCE in this case, will not recover its full cost of capital. I provide an example in Exhibit SCE-18 that substantiates this point.

Q. Please summarize Exhibit SCE-18.

A. Exhibit SCE-18 shows that if the cost of capital is calculated without reference to unamortized expenses and discounts, the resulting weighted average cost of capital, when applied to the rate base, will not be sufficient for the utility to recover its total capital cost, including interest costs and the amortization of expenses and discounts. Although the case of unamortized losses on reacquired debt or preferred equity is not shown in this example, the results would be the same.

Q. What is the key observation you make from Exhibit SCE-18?

A. The key observation is that the rate base cannot exceed the net proceeds from debt and equity issuance. If the weighted average cost of capital ("WACC") is calculated using the book value of equity and the face value of debt, then it will be insufficient to recover the total capital costs of the company. The total cost of capital is calculated in columns H through J. Columns K through M show that recovery using the book value/face value WACC applied to the rate base will be insufficient to recover the total capital costs. On the other hand, columns N through Q show that using a net proceeds-based WACC applied to the rate base will recover the total capital costs.

Q. Without consideration of adjustments for expenses, discounts/premiums, and losses on reacquired securities, would SCE generally over- or under-recover its cost of capital?

A. Generally, SCE would under-recover its cost of capital, because SCE almost always issues securities at a discount to face value.

Q. Could there ever be a situation where omitting these adjustments could cause SCE to over-recover its cost of capital?

A. Although unlikely, yes. A situation of over-recovery could only arise if SCE consistently issued securities at a premium to their face values plus expenses. The process of issuing long-term debt and preferred equity normally involves setting a coupon rate that is evenly divisible by five basis points (such as 5.45% in the case of SCE's Series K bonds) for administrative convenience. This rate is typically below the interest rate that investors will demand for the issue, so the inclusion of a discount when the issue is actually priced for offer raises the interest rate that investors will earn above the coupon rate. It is rare that we observe premiums associated with debt or preferred equity issues. Only one of SCE's currently outstanding long-term debt issues was issued at a premium.

Q. Why do you employ 13-month calculations in lines 1-7, 10-11, 13-15, and 17-21 of Schedule 5?

A. These lines are associated with the calculation of debt and equity balances. These balances are the denominators in the calculation of the amount of long-term debt and preferred equity. The use of a 13-month average improves the accuracy of the amount of long-term debt and preferred equity outstanding. Given the long-term debt and preferred equity balances are calculated using a 13-month average, the common equity balance must be calculated in the same way to produce a consistent set of capital ratios.

Q. Referring to line 9 in Schedule 5, why do you only include the after-tax amount of Unamortized Loss on Reacquired Debt?

A. The formula assumes that any loss on reacquired debt results in an income tax deduction that is recorded when the loss occurs, so that only the after-tax portion of the loss is unrecovered.

Q. What other changes are you proposing as compared to the Second Formula rate?

A. I am proposing a modification to how total proprietary capital is determined in the formula to exclude non-cash net charges against earnings relating to potential damages claims and other costs associated with wildfires in SCE's service territory.

Q. Can you provide an example of a non-cash net charge against earnings associated with wildfires in SCE's territory?

A. On February 28, 2019, SCE filed its 2018 10-K financial report reflecting accrual of a fourth quarter non-cash net charge against earnings due to potential damage claims and other costs associated with 2017 and 2018 wildfires and muslide events in SCE's service territory ("Wildfire Reserve"). In the 10-K, Edison International and SCE stated that they expect to incur a material loss in connection with 2017 and 2018 wildfire events and accrued a charge, before recoveries and taxes, of $4.7 billion in the fourth quarter of 2018. After accounting for expected recoveries, the net charge to earnings recorded was $1.8 billion after-tax. This $1.8 billion reflects costs subject to cost recovery approval by the CPUC.

SCE accrued this charge as required by accounting principles generally accepted in the United States of America ("GAAP"). GAAP requires that a contingent liability be recorded on an accrual basis when liability is probable and reasonably estimable, even though no actual liability has been incurred. Under accounting standards for rate-regulated enterprises, SCE defers costs as regulatory assets when it concludes that such costs are probable of future recovery in electric rates. SCE utilizes objectively determinable evidence to form its view on probability of future recovery. The only directly comparable precedent in which a California investor-owned utility has sought recovery for uninsured wildfire-related costs is San Diego Gas & Electric's ("SDG&E") requests for cost recovery related to 2007 wildfire activity, where the CPUC denied recovery of all CPUC-jurisdictional wildfire-related costs based on a determination that SDG&E did not meet the CPUC's prudency standard.

As a result, while SCE does not agree with the CPUC's decision, it believes that the CPUC's interpretation and application of the prudency standard to SDG&E creates substantial uncertainty regarding how that standard will be applied to an investor-owned utility in future wildfire cost-recovery proceedings. SCE therefore concluded that it lacks sufficient information regarding cost recovery of wildfire-related liability at the CPUC to record an offsetting "regulatory asset" at this time. Accordingly, it accrued the $1.8 billion charge. My proposal excludes such wildfire related non-cash charges ("Wildfire Related Capital") from determining SCE's total proprietary capital.

Q. Why are you proposing to exclude non-cash net charges against earnings associated with wildfires in SCE's territory?

A. The impact of taking the Wildfire Reserve without sufficient offsets lowers SCE's equity ratio under the Second Formula Rate even though no equity has in fact been adjusted. This substantial non-cash net charge is due to the same unsettled legal and regulatory approach—i.e., California's inverse condemnation in conjunction with the CPUC's application of prudency standards to megafire cost recovery—and further negatively impacts investor expectations. To reflect a just and reasonable return on capital, I am proposing that this Wildfire Related Capital should be excluded when determining SCE's total proprietary capital.

Q. Where is the calculation to include non-cash wildfire related net charges in Total Proprietary Capital shown?

A. Schedule 5 ROR-2, line 14a will include any non-cash capital charges related to wildfire liability. Line 18 of Schedule 5 ROR-1 uses the sum of Schedule 5 ROR-2 lines 14 and 14a to calculate the 13-month average Total Proprietary

Capital. This value is then included in the calculation of the Common Stock Equity Amount shown on Schedule 5 ROR-1 line 23.

Q. Does this conclude your testimony?

A. Yes.

DECLARATION

I, Sergio Deana, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 10, 2019 in Rosemead, California

Sergio Deana

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

EXHIBIT SCE-18

EXHIBIT TO THE TESTIMONY OF MR. SERGIO DEANA

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

WHY COST OF CAPITAL MUST ACCOUNT FOR AMORTIZATIONS

DEBT COST

Assumptions:		
Issuance (Face Value):		100,000,000
Maturity (in Years)		30
Coupon		5.00%
Issuance Costs		
Discount	0.05%	50,000
Expense	0.09%	90,000
Total Issuance Cost		140,000
Net Proceeds from Issuance		99,860,000
Total Annual Cost of Debt Service		5,004,667
Annual Cost/Face Value		5.0047%

Debt Cost

(A)	(B)	(C)	(D)	(E)	(F)	(G)
Year	Interest Expense	Amortization (Issuance Costs /Maturity)	Total Cost of Debt Service	Annual Cost/ Face Value	Net Proceeds (Mid-Year)	Annual Cost/ Net Proceeds
0					99,860,000	
1	5,000,000	4,667	5,004,667	5.0047%	99,862,333	5.0116%
2	5,000,000	4,667	5,004,667	5.0047%	99,867,000	5.0113%
3	5,000,000	4,667	5,004,667	5.0047%	99,871,667	5.0111%
4	5,000,000	4,667	5,004,667	5.0047%	99,876,333	5.0109%
5	5,000,000	4,667	5,004,667	5.0047%	99,881,000	5.0106%
6	5,000,000	4,667	5,004,667	5.0047%	99,885,667	5.0104%
7	5,000,000	4,667	5,004,667	5.0047%	99,890,333	5.0102%
8	5,000,000	4,667	5,004,667	5.0047%	99,895,000	5.0099%
9	5,000,000	4,667	5,004,667	5.0047%	99,899,667	5.0097%
10	5,000,000	4,667	5,004,667	5.0047%	99,904,333	5.0095%
11	5,000,000	4,667	5,004,667	5.0047%	99,909,000	5.0092%
12	5,000,000	4,667	5,004,667	5.0047%	99,913,667	5.0090%
13	5,000,000	4,667	5,004,667	5.0047%	99,918,333	5.0088%
14	5,000,000	4,667	5,004,667	5.0047%	99,923,000	5.0085%
15	5,000,000	4,667	5,004,667	5.0047%	99,927,667	5.0083%
16	5,000,000	4,667	5,004,667	5.0047%	99,932,333	5.0081%
17	5,000,000	4,667	5,004,667	5.0047%	99,937,000	5.0078%
18	5,000,000	4,667	5,004,667	5.0047%	99,941,667	5.0076%
19	5,000,000	4,667	5,004,667	5.0047%	99,946,333	5.0074%
20	5,000,000	4,667	5,004,667	5.0047%	99,951,000	5.0071%
21	5,000,000	4,667	5,004,667	5.0047%	99,955,667	5.0069%
22	5,000,000	4,667	5,004,667	5.0047%	99,960,333	5.0067%
23	5,000,000	4,667	5,004,667	5.0047%	99,965,000	5.0064%
24	5,000,000	4,667	5,004,667	5.0047%	99,969,667	5.0062%
25	5,000,000	4,667	5,004,667	5.0047%	99,974,333	5.0060%
26	5,000,000	4,667	5,004,667	5.0047%	99,979,000	5.0057%
27	5,000,000	4,667	5,004,667	5.0047%	99,983,667	5.0055%
28	5,000,000	4,667	5,004,667	5.0047%	99,988,333	5.0053%
29	5,000,000	4,667	5,004,667	5.0047%	99,993,000	5.0050%
30	5,000,000	4,667	5,004,667	5.0047%	99,997,667	5.0048%
Total						

WHY COST OF CAPITAL MUST ACCOUNT FOR AMORTIZATIONS

TOTAL CAPITAL COST AND RECOVERY OF CAPITAL COST

Assumptions:	
Common Equity Outstanding (Book Value)	100,000,000
Long-Term Debt Outstanding (Face Value)	100,000,000

Weighted Average Cost of Capital (Book Value/Face Value)

Cost of Equity	10.30%
Cost of Debt (Face Value)	5.0047%
Equity Ratio (Book Value/Face Value)	50.00%
Weighted Average Cost of Capital (WACC)	7.65233%

	Total Capital Cost			Recovery of Capital Cost At Book Value/Face Value (7.65233%) WACC			Recovery of Capital Cost At Net Proceeds WACC			
(A)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
Year	Total Equity Cost	Total Debt Cost	Total Cost of Capital	Rate Base	Return at Book Value/ Face Value WACC	Under-/Over-Recovery	Rate Base	Net Proceeds WACC	Return at Book Value/ Face Value WACC	Under-/Over-Recovery
0										
1	10,300,000	5,004,667	15,304,667	199,862,333	15,294,132	-10,535	199,862,333	7.6576%	15,304,667	0
2	10,300,000	5,004,667	15,304,667	199,867,000	15,294,489	-10,178	199,867,000	7.6574%	15,304,667	0
3	10,300,000	5,004,667	15,304,667	199,871,667	15,294,846	-9,820	199,871,667	7.6572%	15,304,667	0
4	10,300,000	5,004,667	15,304,667	199,876,333	15,295,203	-9,463	199,876,333	7.6571%	15,304,667	0
5	10,300,000	5,004,667	15,304,667	199,881,000	15,295,560	-9,106	199,881,000	7.6569%	15,304,667	0
6	10,300,000	5,004,667	15,304,667	199,885,667	15,295,917	-8,749	199,885,667	7.6567%	15,304,667	0
7	10,300,000	5,004,667	15,304,667	199,890,333	15,296,275	-8,392	199,890,333	7.6565%	15,304,667	0
8	10,300,000	5,004,667	15,304,667	199,895,000	15,296,632	-8,035	199,895,000	7.6564%	15,304,667	0
9	10,300,000	5,004,667	15,304,667	199,899,667	15,296,989	-7,678	199,899,667	7.6562%	15,304,667	0
10	10,300,000	5,004,667	15,304,667	199,904,333	15,297,346	-7,321	199,904,333	7.6560%	15,304,667	0
11	10,300,000	5,004,667	15,304,667	199,909,000	15,297,703	-6,964	199,909,000	7.6558%	15,304,667	0
12	10,300,000	5,004,667	15,304,667	199,913,667	15,298,060	-6,607	199,913,667	7.6556%	15,304,667	0
13	10,300,000	5,004,667	15,304,667	199,918,333	15,298,417	-6,249	199,918,333	7.6555%	15,304,667	0
14	10,300,000	5,004,667	15,304,667	199,923,000	15,298,774	-5,892	199,923,000	7.6553%	15,304,667	0
15	10,300,000	5,004,667	15,304,667	199,927,667	15,299,131	-5,535	199,927,667	7.6551%	15,304,667	0
16	10,300,000	5,004,667	15,304,667	199,932,333	15,299,489	-5,178	199,932,333	7.6549%	15,304,667	0
17	10,300,000	5,004,667	15,304,667	199,937,000	15,299,846	-4,821	199,937,000	7.6547%	15,304,667	0
18	10,300,000	5,004,667	15,304,667	199,941,667	15,300,203	-4,464	199,941,667	7.6546%	15,304,667	0
19	10,300,000	5,004,667	15,304,667	199,946,333	15,300,560	-4,107	199,946,333	7.6544%	15,304,667	0
20	10,300,000	5,004,667	15,304,667	199,951,000	15,300,917	-3,750	199,951,000	7.6542%	15,304,667	0
21	10,300,000	5,004,667	15,304,667	199,955,667	15,301,274	-3,393	199,955,667	7.6540%	15,304,667	0
22	10,300,000	5,004,667	15,304,667	199,960,333	15,301,631	-3,035	199,960,333	7.6539%	15,304,667	0
23	10,300,000	5,004,667	15,304,667	199,965,000	15,301,988	-2,678	199,965,000	7.6537%	15,304,667	0
24	10,300,000	5,004,667	15,304,667	199,969,667	15,302,345	-2,321	199,969,667	7.6535%	15,304,667	0
25	10,300,000	5,004,667	15,304,667	199,974,333	15,302,703	-1,964	199,974,333	7.6533%	15,304,667	0
26	10,300,000	5,004,667	15,304,667	199,979,000	15,303,060	-1,607	199,979,000	7.6531%	15,304,667	0
27	10,300,000	5,004,667	15,304,667	199,983,667	15,303,417	-1,250	199,983,667	7.6530%	15,304,667	0
28	10,300,000	5,004,667	15,304,667	199,988,333	15,303,774	-893	199,988,333	7.6528%	15,304,667	0
29	10,300,000	5,004,667	15,304,667	199,993,000	15,304,131	-536	199,993,000	7.6526%	15,304,667	0
30	10,300,000	5,004,667	15,304,667	199,997,667	15,304,488	-179	199,997,667	7.6524%	15,304,667	0
Total						-160,699				0

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)		
Southern California Edison Company	)	**Dkt. No.**	**ER19-______-000**
	)		

PREPARED DIRECT TESTIMONY OF
DANIEL WOOD

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-19)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
DANIEL WOOD

(EXHIBIT SCE-19)

Mr. Wood's testimony supports SCE's recommended return on equity ("ROE") of 17.12%. The recommended ROE represents the combined value of the conventional ROE for a utility of above-average risk like SCE without wildfire consideration (11.12%), plus the additional return necessary to account for the wildfire risks faced by SCE (6%). Mr. Wood's testimony also addresses why the proposed ROE, as well as the California Independent System Operator incentive adder and SCE's Commission-approved transmission project-specific incentive adders, are just and reasonable.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
DANIEL WOOD
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Daniel Wood, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. What is your position at SCE?

A. I am Vice President and Treasurer of Southern California Edison (SCE). I am responsible for certain financial operations of the utility.

Q. What is your professional and education background?

A. In my 20 years at Edison, I've held several general manager roles at both SCE and Edison International, including positions in corporate financial planning and long-term finance. I received a bachelor's degree in economics at California Polytechnic University in San Luis Obispo, and a Masters of Business Administration degree from Pepperdine University.

Q. Have you ever testified before the Commission?

A. No.

Q. What is the purpose of your testimony?

A. As the return on equity (“ROE”) policy witness, I will recommend the ROE and ROE incentives that SCE requests and should receive in this case. I am sponsoring Schedule 1, Line 50 “Return on Common Equity.”

Q. What ROE do you recommend?

A. SCE should receive an ROE of 17.12%, in addition to the applicable ROE incentive adders. Specifically, as a member of the California Independent System Operator (“CAISO”), SCE should continue to receive the ROE incentive adder of 0.5%. In addition, the Commission has previously granted ROE incentive adders on three specific transmission projects. These projects, and their associated ROE incentive adders, are: Rancho Vista Transmission Substation Project, 0.75 percent; Tehachapi Transmission Project, 1.25 percent; and Devers-Colorado River Project, 1.00 percent.[1] SCE should continue to receive these project incentives.

Dr. Villadsen provides support for the continuation of these incentives in her testimony in SCE-25.

Q. What is the basis for your ROE request of 17.12%?

A. The 17.12% ROE (i.e., excluding incentive adders) reflects two components. First, given the risks SCE faces excluding those risks associated with wildfires, Dr. Villadsen demonstrates and recommends that SCE should receive an ROE of 11.12%.[2] I refer to this as the “conventional ROE.” Second, given the significant risks associated with wildfires faced by SCE in combination with

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[1] *See Southern California Edison Co.*, 121 FERC ¶ 61,168 at P 129 (2009) and Southern California Edison Co., 132 FERC ¶ 61,213 (2010)

[2] *See* Exhibit SCE-25.

California's inverse condemnation doctrine, Mr. Frank Graves demonstrates and recommends that SCE's investors receive an additional 6.0% ROE. This value accounts solely for wildfire risks and is in addition to the required conventional ROE. As described by Mr. Graves, while any ultimate or specific liability is unknown by investors, under current conditions and despite all reasonable efforts by SCE to mitigate risks, SCE faces the continued specter of potential wildfire cost responsibility that exceeds billions, even exceeding ten billion for a single event, of dollars.

My recommended ROE of 17.12% represents the combined value of the conventional ROE for a utility of above-average risk like SCE without wildfire consideration (11.12%), plus the additional return necessary to account for the wildfire risk faced by SCE (6.0%).

Q. Please provide additional details on why the wildfire risk results in a recommended 6.0% in addition to SCE's conventional ROE.

A. Investors associate significantly higher risk with a common equity investment in SCE when compared to investments in other non-California electric utilities. Given the extraordinary uncertainties stemming from the ongoing application of inverse condemnation and wildfire-related damages to SCE, its equity risks are not comparable to those of non-California electric utilities. As a result, compensation for the much higher risks that investors currently face with an investment in SCE's common equity is not reflected in the results of the Commission's conventional ROE evaluation, which uses a proxy group based on credit ratings for debt.

SCE engaged Mr. Graves, to determine the ROE needed to account for this risk to investors. In his report *California Megafires: Approaches for Risk*

Compensation and Financial Resiliency Against Extreme Events,[3] Mr. Graves describes the increased risk of severe wildfires in California, the damages and costs associated with these fires, and the asymmetric risk borne by utilities as a result of California's wildfires combined with inverse condemnation and California Public Utilities Commission ("CPUC") cost recovery policies. Prior to engaging Mr. Graves, SCE conducted a CPUC-required Risk Assessment and Mitigation Study ("RAMP"), which was submitted in 2018. In the RAMP Study, SCE: identified and evaluated its top safety risks, such as wildfires; evaluated opportunities to mitigate those risks; and proposed mitigation plans for the risks. Mr. Graves leveraged the RAMP study, updated with more recent wildfire information and additional sources of information to estimate the maximum potential liability that SCE could be exposed to as a result of wildfires. He estimated that potential liability to be approximately $12.6 billion (pre-tax) in excess of SCE's current insurance coverage. Mr. Graves, using that potential liability estimate along with the underlying statistical pattern of potential damages, then calculated that an additional $1 billion per year of net income would be required to bear these risks. Given SCE's requested rate base in the 2018 CPUC-jurisdictional General Rate Case, this increase in net income translates to a 6.0% ROE supplement and an appropriate adjustment to the traditional ROE for wildfire risk.[4] I am therefore recommending 6.0% as the appropriate increase to ROE to address wildfire risk.

Investors must have confidence that they have a reasonable opportunity to earn a return on their investment at a level that is commensurate with the

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3 Exhibit SCE-24.

4 *See* Exhibit SCE-22 and SCE-24.

conventional ROE, which is 11.12% for SCE without a consideration of wildfires. Given wildfire risks, the returns must be adjusted upwards based upon the maximum liability that equity holders face. SCE believes the maximum is appropriate for several reasons. First, shareholders are currently subject to the maximum exposure; there is no cap on their liability under the current regulatory construct. Shareholders could lose all equity in the company if wildfire damages prove large enough. Second, as Mr. Graves explains, unlike traditional insurance providers, shareholders do not have a diversified portfolio of events to mitigate risk, which would have justified the use of the mean liability exposure level. Mr. Graves analogizes SCE's shareholders' risk to that of an individual saving for retirement – fiscal prudency requires that individual to save to the maximum life span, not the average one. Third, recent fires in 2018 show that damages from wildfires can rise to very large amounts, exceeding even the $13.6 billion (pre-insurance value) calculated by Mr. Graves.

Q. Does including the 6.0% in addition to the conventional ROE provide a long-term solution for wildfire risk for investors?

A. No. As Mr. Graves explains, the additional ROE to address investors' exposure to wildfire risk is neither a complete solution nor one that can be maintained in the long-term. First, it is difficult to estimate the necessary ROE increase to offset the potential costs investors may face for wildfire losses. Second, a wildfire ROE may create the wrong impression that SCE is fully protected and can withstand any level of wildfire damages – it cannot. While an increased ROE may encourage continued investment in SCE despite wildfire risks, it does not ensure nor is it intended to ensure SCE has the financial wherewithal to absorb all magnitudes of wildfire liability.

Wildfire risk is disproportionately high compared to other risks faced by the company but it is a risk that can be mitigated by policy changes. SCE continues to pursue legislative, regulatory and legal strategies to address the application of a strict liability standard to wildfire-related damages and the prudency standard applied by the CPUC to determine whether a utility can recover these court-assigned costs.

Q. Does SCE believe the 6.0% in addition to the conventional ROE provides an effective long-term solution for wildfire risks for SCE?

A. No. As noted above, an additional ROE to supplement the conventional ROE is not an optimal long-term solution. SCE's wildfire risk, due to climate change effects, drought and other factors, has increased significantly. This risk requires a much more comprehensive solution. Approximately thirty five percent of SCE's territory is located within a high fire risk area – twenty seven percent in CPUC-defined areas and another eight percent in areas designated by SCE.[5] And, many of the factors that contribute to the ignition and spread of California's most devastating wildfires, and their far-reaching consequences, are not within SCE's reasonable control. California wildfire risk is a societal problem and can only be resolved through the informed collaboration of all stakeholders, under the leadership of the State government, with Federal cooperation where appropriate. SCE continues to work actively towards a

[5] Exhibit SCE-20, at pp. 4-5. Dr. Chen notes that the area designated by SCE is under review. *Id. See also* CPUC Rulemaking (R.)18-10-007, *Southern California Edison Company's (U 338-E) 2019 Wildfire Mitigation Plan*, filed Feb. 6, 2019, at p. 28.

comprehensive long-term solution. However, until progress is made, the additional ROE proposed here provides a just and reasonable mechanism to address the risk shareholders face and helps maintain investor confidence in the near-term.

Q. If progress is made toward a long-term wildfire solution, would SCE still require an additional ROE beyond the conventional ROE?

A. It depends on the degree and form of progress. An ideal situation would be where wildfire risk is comprehensively addressed such that wildfires would no longer present a unique and significant risk to SCE, and investors would no longer require the additional ROE. However, should progress be made to reduce risk yet not eliminate wildfires as a substantial risk, the additional ROE could be lowered, but not eliminated.

Q. Under the hypothetical that wildfire risk is comprehensively mitigated and no longer presents a unique risk to SCE, would SCE adjust or remove the 6% additional ROE?

A. Yes. With the wildfire risk fully addressed, the additional ROE would no longer be appropriate, and investors would be adequately compensated with the conventional ROE for an above-average risk utility. In this case, SCE would file with the Commission to adjust its ROE accordingly by removing the 6.0% associated with wildfire risks.

Q. Does SCE's conventional ROE, in conjunction with all Commission incentives, fall within a Zone of Reasonableness?

A. Yes. SCE's conventional ROE of 11.12% plus the CAISO ROE incentive of 0.5% plus SCE's highest individual transmission ROE incentive of 1.25% for Tehachapi totals 12.87%.

Dr. Villadsen calculates a Zone of Reasonableness for SCE based on a comparison of electric utilities. The values in her analysis represent a Zone of Reasonableness that does not reflect the impact of wildfires. Based on this comparison, Dr. Villadsen calculates a Zone of Reasonableness for SCE of at least 12.5%.[6] However, as noted by Dr. Villadsen, the Commission's conventional measurements for reasonable ROEs produce values, after excluding outliers, as high as 14.4% under the Expected Earnings model.[7]

Q. Does SCE's requested ROE of 17.12%, which considers the impact of wildfires, when combined with the CAISO incentive adder of 50 basis points fall within a Zone of Reasonableness?

A. Yes. First, Dr. Villadsen concludes that, because of the unique wildfire related risks faced by SCE, those wildfire related risks are not captured by the Zone of Reasonableness of conventional electric utilities. Instead, Dr. Villadsen identifies a set of capital-intensive network-based companies to serve as a more appropriate proxy group for SCE rather than one comprised of only electric utilities. And while these companies in the updated proxy group do not have the same wildfire risk as SCE, they face other risks that make them more comparable to SCE than the conventional electric utility-only proxy group.[8] Using this more appropriate proxy group, Dr. Villadsen calculates a Zone of Reasonableness for SCE of at least 18.2%.[9]

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6 Exhibit SCE-25, at p. 40.

7 *Id.*, at Table 6.

8 *Id.*, at p. 52.

9 *Id.*, at p. 53.

Importantly, after excluding outliers and again following the Commission's measurements for ROE, the updated proxy group produces values as high as 19.9% under the Two Stage DCF model, and 26.4% under the Expected Earnings model.[10] Thus, in light of the wildfire risks faced by SCE, and given that SCE's ROE request of 17.12% when combined with the CAISO incentive of 50 basis points falls well below other companies in the proxy group that have returns as high as 26.4%, the Commission should find that SCE's request is reasonable.

Q. The Tehachapi project has SCE's highest project incentive of 1.25%. Based on your request, what is the total ROE the project will receive?

A. It will receive the Base ROE of 17.12% plus the CAISO incentive of .5% plus the specific project incentive of 1.25% for a total ROE of 18.87%.

Q. Should the Commission consider this request for Tehachapi reasonable?

A. Yes. As noted by Dr. Villadsen, the updated proxy group yields ROEs, after excluding outliers, as high as 26.4%. The combined total ROE of Tehachapi, 18.87%, is well below this value.

Q. Does this conclude your testimony?

A. Yes.

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[10] *Id.*, at Tables 9 and 10.

DECLARATION

I, Daniel Wood, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 9, 2019 in Rosemead, California

Daniel Wood

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
BRIAN CHEN

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-20)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	)))	**Dkt. No. ER19-______-000**

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
BRIAN CHEN

(EXHIBIT SCE-20)

Dr. Chen provides an overview of some of the actions SCE is taking or proposing to take to address wildfire risks associated with its infrastructure on the distribution and transmission-level grids. These actions are intended to reduce the likelihood of electrical infrastructure-associated ignitions that could lead to wildfires, make the grid more resilient in the presence of a wildfire, and provide greater situational awareness to SCE grid operators and first responders such as fire crews and SCE line crews. While SCE can and is taking these prudent and innovative actions, they will require years to fully implement and the sum total of these actions cannot address all issues and potential risks SCE faces associated with wildfires.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
BRIAN CHEN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Brian Chen, and my business address is 1 Innovation Way, Pomona California 91768-1001.

Q. Please briefly describe your present responsibilities at Southern California Edison ("SCE" or "Edison").

A. I am a Principal Manager of SCE's Grid Resiliency and Public Safety Program Management Office. In this capacity I oversee the day-to-day operations of the group responsible for enterprise-wide operational mitigation efforts for wildfire and other public safety risks.

Q. Please briefly describe your educational and professional background.

A. I joined SCE in 2011 and in my previous roles at SCE, I served as a Project Manager in Regulatory & Strategic Planning, Senior Manager in Transmission & Distribution ("T&D") Business Planning, and Principal Manager in T&D Engineering Business Strategy & Operations Support. Prior to joining SCE, I was a partner with an investigative engineering consulting firm in Texas and was an Assistant Professor in the Civil Engineering Department at Bucknell

University. I hold a Master of Business Administration from the University of California, Los Angeles Anderson Graduate School of Management, along with a Bachelor of Science from Purdue University, and a Master of Science along with a Doctor of Philosophy in Civil Engineering from the University of Texas at Austin.

Q. Have you submitted testimony or affidavits to the Commission previously?

A. No.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe some of the actions SCE is taking or proposing to take to address wildfire risk on SCE's distribution and transmission grids. In particular, my testimony will highlight actions SCE is already taking, and plans to take, to mitigate the threat of electrical infrastructure-associated ignitions that could lead to wildfires, to further harden SCE's electrical system against wildfires, and to support greater situational awareness to first responders and SCE's grid operators, line crews, and incident response personnel.

Q. Are the wildfire mitigations you will be describing in your testimony sufficient to completely address SCE's wildfire risk?

A. No. Although SCE has and will continue over the next 5-7 years to make system and operational refinements to SCE's distribution and transmission system in response to wildfire risks, contributing wildfire factors outside of SCE's control still exist. These contributing factors include climate conditions, vegetation and forest management activities beyond what SCE performs surrounding its grid infrastructure, density of structures in close proximity or within the wildland-urban interface within SCE's territory, the amount of SCE's service territory within High Fire Risk Areas, fire agency resources and suppression response capabilities, along with fire ignitions caused by other sources. In addition, none of these system or operational refinements address the financial risk attributable to the application of the inverse condemnation doctrine to California based utilities as discussed by Mr. Graves in SCE-22 and SCE-24.

II. BACKGROUND ON T&D's ACTIVITIES TO ADDRESS WILDFIRE RISK

Q. What has changed with regards to the wildfire risk in California?

A. California's wildfire risk has increased in recent years due to climate conditions, drought, and other factors such as increased development in the wildland-urban interface and significant buildup of fuel, including on federal and state forest lands. The potential magnitude of the increased threat and the significance of its consequences did not become apparent until late 2017. The 2017 and subsequent wildfires in 2018 (eight of the 20 most destructive wildfires in California history) destroyed more than 31,000 structures, double the number consumed by the earlier twelve. I emphasize that California's wildfire risk has increased to the point where the safety of our communities requires additional measures designed to address the significantly higher level of wildfire risk.

Q. What is a High Fire Risk Area?

A. SCE defines High Fire Risk Areas ("HFRA") within its service territory as those areas that include the California Public Utilities Commission ("CPUC")-defined High Fire Threat Districts ("HFTD"), as well as locations previously identified by SCE as high fire risk. The CPUC's HFTDs were adopted as part of CPUC Decision 17-12-024, issued on December 21, 2017, and include areas considered to be "elevated risk" (Tier 2) and "extreme risk" (Tier 3) for wildfires. Prior to the creation of the CPUC's HFTDs, SCE in 1996 designated portions of its service area as high fire risk based upon California Department of Forestry and Fire Protection's ("CAL FIRE") Fire Hazard Severity Zone maps. Prior to 1996, SCE also used internal data sources on fire history, fuels, wind, and urban construction to determine its HFRA boundaries.

Q. What portion of SCE's service territory is located within an HFRA?

A. Currently, approximately 35% of SCE's service territory resides within the HFRAs. Of this, approximately 27% consists of the CPUC's Tier 2 and Tier 3 HFRAs and the remaining 8% consists of areas previously designated by SCE as high fire risk.

Q. Does SCE plan reevaluate the wildfire risks of the approximately 8% that falls outsides the CPUC Tier 2 and Tier 3 areas?

A. Yes. As part of SCE's recently filed Wildfire Mitigation Plan, SCE noted "Going forward, SCE will assess if the areas currently designated as HFRA that are beyond the CPUC's HFTD continue to pose significant wildfire risk sufficient to remain designated as HFRA. SCE's HFRA designations will be updated as a result of the assessment in 2019."[1]

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[1] CPUC Rulemaking (R.)18-10-007, *Southern California Edison Company's (U 338-E) 2019 Wildfire Mitigation Plan*, filed Feb. 6, 2019, at p. 28.

Q. If SCE ultimately reclassifies some of the area associated with the 8% HFRA to a non-HFRA designation, what impact would this reduction have on SCE's wildfire risk?

A. Conceptually, any reduction should have no material impact on SCE's wildfire risk because only areas that were determined to have low to no wildfire risk would be removed.

Q. What is the importance of an HFRA designation? How does it impact SCE's wildfire mitigations?

A. Fire mitigations have been an integral part of SCE's operational practices for years in recognition of the large portion of SCE's territory located with an HFRA. Both existing and proposed enhanced practices and supporting mitigations within SCE's HFRA are discussed within my testimony.

Q. What are SCE's existing efforts to mitigate wildfire risk on transmission circuits located within the HFRA?

A. Historically, SCE's inspection and maintenance programs have been developed and executed with a focus on compliance with regulatory requirements, and SCE has developed multiple inspection and supporting programs over time to meet various compliance obligations. SCE's existing efforts include a Transmission Inspection Maintenance Program that performs scheduled inspections and associated maintenance in accordance with state regulatory requirements, SCE standards, and prudent utility practice; annual vegetation management activities to perform trimming or removal trees and other vegetation to mitigate ignition risks; proactive and reactive road and right-of-way maintenance that are also used by fire agencies as fire breaks and for access during emergencies; insulator washing to remove contamination that can cause unintended arcing and short circuits; and use of infrastructure protection teams that activate during wildfire events to coordinate with first responders, provide information to California's Independent System Operator ("CAISO") to manage the bulk electric system, and coordinate SCE's response to repair damage and restore the electric system following system outages.

SCE also has in place a Red Flag Warning Program that enacts operational changes to specifically address the elevated threat of wildfires. This program is activated when the fire potential index determined by the U.S. Forest Service, the National Interagency Coordination Center's Predictive Services and other collaborators, reaches a Red Flag warning wildfire threat level or greater. Upon program activation, SCE and fire agencies pre-deploy personnel and equipment in high fire hazard areas to spot and quickly extinguish fires in their incipient stage. SCE personnel conduct patrols and serve as lookouts for ignitions and prominently display "Red Flag Fire Patrol" signs on their vehicles to deter potential arsonists. Work performed in HFRA by SCE personnel or contractors is also restricted to very limited circumstances to minimize potential work-caused ignitions. Lastly, the operation of remote-controlled switches are performed, when possible, under visual observation to detect abnormalities that could lead to an ignition.

SCE has also been conducting a Transmission Line Rating study to identify transmission lines with potential clearance issues. As part of this study, SCE completed an initial survey of all of SCE's CAISO-controlled transmission lines built before 2005. Based on the results of that survey, SCE prioritized transmission line discrepancies requiring line clearance remediation. A discrepancy is any condition found in the field requiring remediation to meet both CPUC General Order 95 and NERC clearance code requirements during peak-loading conditions. Discrepancies have been prioritized based on criteria such as line sag when operating at or below 130 degrees Fahrenheit, and potential risk to public safety and system reliability based on location of span, terrain, encroachment type and extent of deviation from standards. In 2015, SCE developed a plan to remediate all discrepancies on CAISO-controlled transmission lines over a ten-year period, from 2016 to 2025.

Q. Do SCE's existing practices to mitigate wildfire risk contemplate the need to proactively de-energize circuits?

A. Yes. SCE proactively de-energizes circuits if data sources indicate that extreme local weather conditions pose an imminent and significant threat to public safety associated with the risk of wildfire. The significant complexity and variability of weather and environmental conditions across SCE's service territory, coupled with climate effects and severe drought/bark beetle issues, require flexible de-energization guidelines that can be used under a variety of weather conditions, physical circumstances (*e.g.*, proximity to vegetation), and electrical system operating conditions. SCE's de-energization protocol, officially titled Public Safety Power Shut-Off ("PSPS"), consists of a set of de-energization and re-energization protocols and guidelines with a wide variety of factors considered. SCE's Grid Safety and Resiliency Program ("GSRP") and 2019 Wildfire Mitigation Plan ("WMP") discussed within my testimony, include enhanced grid hardening measures (e.g., deployment of covered conductor) that should reduce the future need for PSPS deployment once fully deployed across SCE's HFRA.

Q. Will SCE implement a PSPS protocol at the transmission level or is this only done on the distribution system?

A. Yes, SCE is planning to include its transmission lines in its PSPS protocol. The nature of the protocols for transmission lines will differ from SCE's distribution lines due to differences in the infrastructure design configurations and standards, susceptibility to conditions that could cause ignitions, impacts to customers and the bulk transmission system, and other factors.

Q. Is SCE pursuing any additional mitigation measures on its Transmission and Distribution system to help mitigate wildfire risk beyond those mandated by existing prescriptive regulatory requirements?

A. Yes. California fires occurring in 2017 and 2018 emphasize that California's wildfire risk has increased to point that necessitates additional measures designed to address a higher level of wildfire risk not contemplated by existing state standards or traditional utility fire mitigation practices. Accordingly, SCE comprehensively reviewed its fire mitigation strategies and developed enhanced measures for HFRA.

Specifically, on September 10, 2018, SCE filed the GSRP with the CPUC. In the GSRP, SCE makes various proposals to further address wildfire risks, including addressing "Grid Hardening," "Enhanced Situational Awareness," and "Enhanced Operational Practices." SCE's GSRP is primarily focused on its distribution system, but also has benefits to SCE's transmission system.

In addition, on February 6, 2019, SCE filed with the CPUC its proposed 2019 WMP. The plan sets forth SCE's proposed 2019 wildfire-mitigation-related programs and activities that complement, and in some cases go beyond, those set forth in the GSRP. At a high level, SCE's 2019 WMP proposes programs and activities that SCE believes will reduce the frequency and consequences of ignitions associated with SCE's electrical infrastructure. The plan is the first in a new annual submission process required in accordance with California Senate Bill 901[2] and represents an incremental step toward addressing rapidly growing wildfire challenges in California.

Q. Has the CPUC approved the GSRP proposal or the Wildfire Mitigation Plan?

A. Not yet. Both are currently pending before the CPUC.

Q. What is "grid hardening" and what has SCE proposed in its GSRP to address it?

A. "Grid Hardening" includes enhancing the existing electrical grid to lower the likelihood of electrical equipment initiating a wildfire or improve the grid's ability to withstand a wildfire. The core objective is to create a more resilient grid that will protect customers from increased wildfire risk and also be able to better withstand wildfire events. SCE's GSRP includes the following Grid Hardening measures within its HFRA, focused primarily on the distribution system:

- Deploying covered conductors to reduce the risk of ignition by preventing faults caused by foreign objects contacting bare conductors;
- Adding fire resistant cross-arms and poles;
- Installing or replacing fuses that activate more quickly to reduce the energy transmitted to faults, thereby further reducing the risk of ignitions from faults;
- Expanding "blocking" of automatic reclosing (where possible) as well as use of a more sensitive "fast curve" setting during Red Flag Warnings for existing remote-controlled automatic reclosers ("RARs")

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[2] Cal. Pub. Util. Code §8386.

and selected substation Circuit Breakers ("CBs") that protect circuits; and

- Installing additional RARs and upgrading selected substation CBs with these advanced protection features, which may reduce the frequency and duration of some power interruption events as described in more detail below.

Q. What is "Enhanced Situational Awareness" and what has SCE proposed in the GSRP to address it?

A. "Enhanced Situational Awareness" includes access to real-time, critical information concerning evolving weather conditions and the current operational status of the electrical grid. This information is provided to key stakeholders including emergency management personnel, the grid operator, and in some cases front-line responders such as fire crews and SCE's line crews in order to help plan for and mitigate potential fire ignitions. SCE's GSRP includes multiple approaches to gather and analyze real-time conditions on the grid including the following:

- Deploying additional weather stations along circuits in HFRA to gather information on localized weather conditions relevant to wildfires including wind speed and direction, temperature and relative humidity;
- Installing high definition (HD) cameras that will enable state and local fire agencies, as well as SCE emergency management staff, to more quickly identify, assess, and respond to wildfires;
- Deploying advanced computer hardware and state-of-the-art software that will run a sophisticated high resolution weather model to support planning and operational decisions to reduce wildfire risk.

Q. What are "Enhanced Operational Practices" and what proposals were included to address them in the GSRP?

A. "Enhanced Operational Practices" includes supplementing or refining inspection and maintenance programs as well as other operational activities to strengthen fire prevention and keep pace with the evolution of wildfire threats. In the GSRP, SCE's proposals include:

- Enhancing SCE's vegetation management program by proactively assessing and, as needed, mitigating trees that pose a blow-in / fall-in threat to electrical facilities but are located outside traditional compliance-driven pruning areas and are not dead, dying, or diseased;
- Further revising SCE's current approach to vegetation management under and around transmission lines to obtain a 30 foot clearance for power lines 115kV and above as achievable;
- Increasing infrared inspections of SCE's distribution system to identify "hot spots" not readily apparent from visual inspections, which indicate increased likelihood of near term wire or equipment failure, and proactively remediating these conditions before a potential failure occurs;
- Deploying, as necessary, mobile generators to provide electricity to certain Essential Use[3] customers in the event SCE must initiate interruption protocols (shut off power in local areas) during high fire-risk conditions.

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[3] Essential Use customers are defined by the California Public Utilities Commission as those that provide essential public health safety, and security services. *See* CPUC General Order 166. Examples include agencies providing essential fire or police services, hospitals and skilled nursing facilities, communication utilities, facilities supporting fuel and transportation services, water and sewage treatment utilities, and others.

Q. GSRP is primarily focused on the distribution system. How does GSRP interact with the transmission system?

A. SCE follows a comprehensive risk management evaluation protocol to assess enterprise-wide safety risks and develop appropriate mitigation measures. One of the key evaluation metrics is Safety, which includes a consideration of wildfire risk. The CPUC recently adopted a new risk mitigation procedure that requires utilities to evaluate their top safety risks using a defined methodology in advance of their General Rate Cases. The evaluation process and results are outlined in each utility's Risk Assessment Mitigation Phase ("RAMP") filing. Pursuant to the RAMP process, SCE adapted its multi-attribute probabilistic risk evaluation model that included the evaluation of safety risks (including safety related risks and the associated probability and consequences of potential wildfire events) to conform to the CPUC's desired format. Based on the results of SCE's risk-informed decision making process, SCE identifies and prioritizes required work, funding and resources.

However, while GSRP mitigations primarily target distribution-level voltages, some mitigation measures will reduce fire risk for transmission facilities. These include, for example, situational awareness mitigation measures including HD cameras, weather stations, and advanced weather models. In addition, distribution lines are occasionally located below transmission lines, and consequently, measures applied to these distribution lines will provide some risk reduction benefit for the overhead transmission lines. SCE intends to further examine fire risk mitigation measures for transmission facilities.

Q. Have there been any relevant material developments related to wildfires since SCE filed the GSRP?

A. Unfortunately, yes. The Woosley Fire began on November 8, 2018, and severely impacted SCE's service territory, ultimately becoming the seventh most destructive wildfire in California history.[4] According to California Department of Forestry and Fire Protection ("CalFire"), it burned 96,949 acres, destroyed 1,643 structures and damaged 364 others,[5] as well as resulting in three civilian fatalities and three firefighter injuries.[6]

The Camp fire started on November 8, 2018 in Pacific Gas and Electric's service territory and burned 153,336 acres and destroyed 13,972 residences, 528 commercial buildings, and 4,293 other buildings, as well as resulting in 86 civilian fatalities and three firefighter injuries.[7] The Camp Fire was the most destructive and deadly wildfire in California's history.[8]

Q. What are some of the key elements and activities described in the Wildfire Mitigation Plan?

A. In addition to the grid hardening, enhanced situational awareness, and enhanced operational practices described in the GSRP, SCE's 2019 WMP

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[4] CalFire, Fact Sheet *Top 20 Most Destructive California Wildfires*, March 14, 2019, *available at* http://fire.ca.gov/communications/downloads/fact_sheets/top20_destruction.pdf.

[5] CalFire, *Woolsey Incident Damage Inspection Report* CA-VNC-91023 (Nov. 20, 2018), at p. 7.

[6] *Woolsey Fire Incident Information* (updated Jan. 4, 2019), *available at* http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=2282.

[7] *Camp Fire Incident Information* (updated Jan. 4, 2019), *available at* http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=2277.

[8] CalFire, Fact Sheet *Top 20 Most Destructive California Wildfires*, March 14, 2019, *available at* http://fire.ca.gov/communications/downloads/fact_sheets/top20_destruction.pdf.

describes a wide range of strategies, programs, and activities that are in place or are being implemented to proactively address and mitigate the threat of electrical infrastructure-associated ignitions that could lead to wildfires. The key elements of the Wildfire Mitigation Plan include descriptions of SCE's methodology for identifying and evaluating wildfire-related risks; wildfire prevention strategies, which include operational practices such as SCE's Red Flag Warning Program and Wildfire Infrastructure Protection Teams, maintenance and inspection programs; system hardening programs and actions; vegetation management programs and activities; protocols for obtaining and utilizing situational awareness information; PSPS protocols; use and evaluation of alternative technologies; and emergency preparedness, response, and customer service-related plans.

One key activity of note described in SCE's 2019 WMP is an Enhanced Overhead Inspection ("EOI") effort SCE launched in December 2018, which consists of supplemental inspections beyond existing inspection programs mandated by regulatory requirements, to identify conditions that may represent near-term wildfire ignition risks. SCE plans to conduct these visual inspections on 100 percent of SCE's distribution and transmission overhead infrastructure that traverses SCE's HFRA. SCE will evaluate findings from these inspections and prioritize potential remediation efforts, considering the likelihood of equipment failure, likelihood of potential ignition, potential consequences of ignition, along with other operational considerations.

Q. Are there specific plans for SCE's transmission system in the Wildfire Mitigation Plan?

A. Yes, many of the existing operational practices described previously encompass SCE's transmission infrastructure located within HFRA.

First, SCE recently redesigned its Vegetation Management Program to include a Transmission Vegetation Management Plan that enhances the utility's existing approach to managing vegetation under and around transmission lines. Directly under conductors, SCE will make every reasonable effort to attempt to clear all trees and brush which could potentially grow into the compliance clearance space around conductors. In the areas between the outer-most conductors and the right-of-way border, SCE will make every reasonable effort to attempt to clear brush and trees that have the potential to strike electric facilities. Lastly, SCE will use Light Ranging and Detection ("LiDAR") technology, which can precisely measure distances of objects in its field of view to create digital three-dimensional representations of the objects scanned. This information will then be used to identify trees along the right-of-way border that could potentially contact conductors during high wind events.

Second, as part of SCE's Enhanced Overhead Inspections of transmission infrastructure within HFRA, SCE will utilize Infrared ("IR") and Corona ultraviolet light ("Corona") sensors to identify potential conditions that are not detectable through visual inspections. These sensors are typically mounted to helicopters that fly along the length of the line to perform the scanning. The IR and Corona scans will focus on splices, conductor connection/attachment points and insulators. Similar to the distribution IR scanning described previously, these scans detect temperature differences and heat signatures of components, which may indicate problems that are not visible to the naked eye and which could result in component/conductor failure. The Corona scans detect the degree of electric discharge or 'leakage' due to the ionization of air surrounding high voltage electric components, which, if substantial enough, could result in an arc flash or mechanical component failure. Additionally, when an IR or Corona scan detects an anomaly, a high definition camera will record a picture of the element so that subject-matter experts can perform further review. Conditions requiring remediation will be identified and prioritized in a similar fashion as conditions discovered from the visual Enhanced Overhead Inspections described previously.

Lastly, to further mitigate wildfire ignition risks, SCE will factor the results from this EOI initiative into the continuous improvement of SCE's Quality Oversight/Quality Control programs and the design and construction of transmission facilities.

Q. Why does SCE's wildfire risk still exist even with the extensive wildfire mitigations discussed with your testimony?

A. As discussed within my testimony, SCE is taking or proposing a number of actions to address wildfire risks on its distribution and transmission grids. These actions are intended to reduce the likelihood of electrical infrastructure-associated ignitions that could lead to wildfires, make the grid more resilient in the presence of a wildfire, and provide greater situational awareness to SCE grid operators and first responders such as fire crews and SCE line crews. While SCE can and is taking these prudent and innovative actions, the capital-based mitigations discussed within my testimony (*e.g.*, Grid Hardening related mitigations) will require years to fully implement. And, critically, the sum total of these actions cannot address all issues and potential risks SCE faces associated with wildfires under California's "new abnormal" environment for wildfire risk. A significant portion of SCE's territory is located within a HFRA. Additionally, many of the factors that contribute to the ignition and spread of California's most devastating wildfires, and their far-reaching consequences, are not within SCE's reasonable control. In the end, California wildfire risk is a societal problem, and one that can only be "solved" through the informed collaboration of all stakeholders, under the leadership of the State government. SCE continues to actively participate in that process, and the wildfire mitigation programs and activities I describe in this testimony are intended to help facilitiate it.

Q. Does this conclude your testimony?

A. Yes.

DECLARATION

I, Brian Chen, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 8, 2019 in Pomona, California

Brian Chen

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)		
Southern California Edison Company	**)**	**Dkt. No.**	**ER19-______-000**
	)		

PREPARED DIRECT TESTIMONY OF GARY STERN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-21)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
GARY STERN

(EXHIBIT SCE-21)

Dr. Stern describes many of the unique risks, beyond wildfires, that SCE faces as a utility within California's current regulatory environment. Risks that Dr. Stern addresses include: (1) unique risks SCE faces due to California environmental and other policies; (2) risks relating to SCE's role in procurement; (3) risks relating to California's approach to retail electric competition and associated load uncertainty; (4) risks relating to regulatory lag in California; and (5) risks relating specifically to SCE's transmission assets.

In addition, Dr. Stern discusses SCE's participation in the CAISO and outlines benefits such participation provides, including economic efficiencies, more efficient asset utilization and reliability benefits to SCE's customers.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
GARY STERN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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

A. My name is Gary Stern, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am the Managing Director of State Regulatory Operations. The responsibilities of this function include determining revenue requirements, filing tariffs and advice letters, rate design, load research, case administration, and related communications and filings the California Public Utilities Commission ("CPUC").

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts degree in Mathematics and Economics from the University of California at San Diego in 1979. I completed my Masters degree in Economics at the University of California at San Diego in 1981, and I received a Doctor of Philosophy degree from the University of California at San Diego in 1984. I was hired as an analyst performing econometric studies at

Southern California Edison in 1984. From there I progressed into resource planning. I became the manager of Integrated Resource Planning in 1991. In 1995 I became the Manager of Restructuring Strategies. In 1998 I became the Director of Market Monitoring, a position I held until 2006 when my responsibilities were expanded to Senior Director of Market Strategy & Resource Planning. In 2013 I became the Senior Director of Energy Policy until I assumed my current position in March of 2018.

Q. Have you submitted testimony to the Commission previously?

A. Yes, in EL00-95 and EL00-98.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a summary of the regulatory and legislative risks SCE faces as a California electric utility. I also describe SCE's participation in the CAISO and outlines benefits such participation provides, including economic efficiencies, more efficient asset utilization and reliability benefits to SCE's customers.

Q. Can you please provide a summary of your testimony?

A. Section II provides an overview of the risks SCE faces as a California electric utility.

Section III discusses the unique risks SCE faces due to California environmental and other policies.

Section IV outlines risks relating to SCE's role in procurement.

Section V outlines risks relating to California's approach to retail electric competition and associated load uncertainty.

Section VI outlines risks relating to regulatory lag in California.

Section VII risks relating specifically to SCE's transmission assets.

Section VIII does not address risks. Rather, it discusses SCE's participation in the CAISO and outlines benefits such participation provides, including economic efficiencies, more efficient asset utilization and reliability benefits to SCE's customers.

II. OVERVIEW OF SCE's RISK PROFILE

Q. What is the most immediate risk that SCE is facing?

A. Wildfires pose the most immediate and catastrophic risk for SCE. As a result of a confluence of factors, wildfires have become a year-round phenomenon with increasing severity.[1] The intensity of California wildfires has become worse over time, as two-thirds of the state's largest fires on record have occurred in the last 20 years.[2] Under the legal doctrine of inverse condemnation, SCE faces strict liability for damages resulting from fires caused by its utility equipment. And, SCE is exposed to significant cost-recovery uncertainty for those damages due to the recent CPUC decision

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1 "Wildfire Awareness Week" Declared in California, May 7, 2018, *available at* http://calfire.ca.gov/communications/downloads/newsreleases/2018/WAWNewsRelease_2018_FINAL.pdf ("Already this year [May 7, 2018], CAL FIRE has responded to more than 950 wildfires that have burned over 5,800 acres. We need Californians to accept fire as part of our natural landscape, understand the potential fire risk, ... CAL FIRE's 'Ready for Wildfire' app is the perfect tool to use in year-round preparation.").

2 CalFire, Fact Sheet *The Top 20 Largest California Wildfires*, March 14, 2019, *available at* http://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Acres.pdf,

disallowing cost recovery for SDG&E's 2007 wildfire.[3] Mr. Graves discusses these risks in Exhibits SCE-22 and SCE-24.

Q. What are the significant risks SCE is facing aside from the risk of wildfires?

A. Because SCE is located in California, SCE faces many regulatory and legislative risks that are not faced by most of the other electric utilities in the United States. California has embarked on major electricity-related transformations on more than one occasion. These disruptions in the status quo, while certainly resulting in environmental and other public benefits, have a proven track record of enhancing risk to the California utilities, including SCE. In the not-too-distant past, this legal and regulatory environment led to the California energy crisis that drove SCE's most comparable neighboring utility, Pacific Gas & Electric ("PG&E") into bankruptcy and pushed SCE to insolvency where it narrowly avoided bankruptcy. Today, as the state enters uncharted legal and regulatory territory to address climate conditions and air pollution, this legal and regulatory environment is once again increasingly under strain in California, and presenting risks to the financial health of its utilities. PG&E has now declared bankruptcy twice in less than 20 years. Both filings were in large part the result of the regulatory and legal framework in California. SCE operates in this very same risky environment.

California is a leader in addressing climate change and air pollution, with the legislature and the CPUC spearheading an industry transformation towards

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3 CPUC Decision (D.)17-11-033, *Decision Denying Application* (issued December 6, 2017); *reh'g denied,* D.18-07-025 *Order Denying Rehearing of D.17-11-033* (July 12, 2018).

a clean energy future. SCE is committed to this clean energy future, through use of renewable energy, energy storage, energy efficiency programs, and using a cleaner grid to improve the transportation sector and building performance through electrification.[4] However, to achieve the state's aggressive environmental policy objectives, SCE faces a significant level of planning and cost recovery risk associated with designing and operating a grid that can safely and reliably support these objectives. California's aggressive Renewables Portfolio Standard ("RPS") and other clean energy goals, and the proliferation of Distributed Energy Resources ("DERs") such as rooftop solar create significant challenges to traditional grid planning and operations, as well as the role of the utility in the presence of expanding retail customer choice. In turn, these factors combine to create significant challenges to SCE as a utility.

SCE's role in California's evolving approach to energy procurement coupled with the increasing amount of electric retail competition, creates significant uncertainty regarding what will happen to SCE's existing energy portfolio, what SCE's future procurement requirements will be, and what customers SCE will be expected to procure energy for. This multifaceted uncertainty presents unique financial risks to SCE. Indeed, the President of the CPUC recently acknowledged: "In the last deregulation, we had a plan, however flawed. Now, we are deregulating electric markets through dozens of

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[4] Indeed, SCE published *The Clean Power and Electrification Pathway* to outline its commitment. *See SCE, The Clean Power and Electrification Pathway* (November 2017), *available at* https://www.edison.com/content/dam/eix/documents/our-perspective/g17-pathway-to-2030-white-paper.pdf.

different decisions and legislative actions, but we do not have a plan. If we are not careful, we can drift into another crisis."[5]

All these risks are amplified by California's ongoing regulatory lag, creating more uncertainty.

III. UNIQUE RISKS FACING SCE DUE TO CALIFORNIA ENVIRONMENTAL AND OTHER POLICIES

Q. Why do California's ambitious and untested environmental objectives create risk for SCE?

A. While many of California's goals offer the promise of significant benefits, the challenges faced to reach these goals can hardly be overstated. The transition to a carbon-free electric grid is nothing short of a full transformation of traditional utility operations and planning. While the end goals have been determined, no comprehensive plan on how to achieve these goals, or how to ensure the financial health of SCE during this transition, exists. Moreover, reaching these goals will ultimately take decades, and thus SCE faces sizeable challenges for the foreseeable future.

Working as an impetus for many of these goals are the rapidly developing technologies needed for a low carbon grid. These include distributed solar generation, energy storage, and increasingly complex demand response implementations. Again, while these technologies hold great promise, many lack a long-term track record of cost effective or reliable operations, many will

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[5] California Customer Choice, An Evaluation of Regulatory Framework Options for an Evolving Electricity Market (August 2018), at iii, *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf.

require changing the way the utility plans for grid expansion, changing the way the grid operates, and changing the way the utility collects costs. On top of this, the rate of technological advancement may make today's decisions look excessively costly or obsolete when compared to tomorrow's new offerings. This rapid innovation creates additional risk to investors concerning the recovery of costs. Moreover, new technologies may replace traditional investment, and in some case have already resulted in the delay or cancellation of planned transmission. Give the unproven nature of the new technology and its application to address issues historically resolved through traditional utility investment, SCE faces risks that the new approaches may not perform as anticipated. And further, that the cancelled projects, or some variations thereof, may still be needed and now must be constructed in very short order. This creates risks not only to reliability, but also to SCE in that it may have to take unanticipated, and capital intensive actions, on very short notice. This puts future risk and pressure as investors have less certainty in the utility's traditional investment opportunities under this new paradigm.

Unfortunately, the legal and regulatory environment in which SCE operates has a poor track record on addressing significant challenges a timely manner and California utilities are currently under additional scrutiny from investors and credit rating agencies.

Q. Do California's Renewables Portfolio Standard and other clean energy goals, as well as the proliferation of Distributed Energy Resources create risks to SCE that are not found in typical utilities?

A. Yes. California is in the middle of an industry transformation, spearheaded by the California legislature and the CPUC. California has some of the most aggressive renewable goals in the nation.[6] When originally passed in 2011, the California RPS required electric utilities to procure 33 percent of their electricity from renewable energy sources by 2020. In 2015, Senate Bill 350 established a goal of 50 percent by 2030. Then in 2018, SB 100 increased the requirement to 60 percent by 2030 and set a 100 percent clean electricity goal for the state by 2045.

These goals are among the most ambitious in the nation and place SCE at the forefront of dramatic and untested industry change. Notably, while the goals and requirements have been set, there currently is no clear plan or path on how these transformational reforms will unfold in order to realize the desired end results. Moreover, there is great uncertainty on how to reach these ends while preserving safety, reliability and affordability, as well as maintaining the financial health of the utilities impacted by this significant transformation. SCE faces significant risks during this transformation, and will likely face major challenges for years to come.

For example, California utilities will need to address the grid reliability and operational challenges associated with this dramatic and rapid change in moving away from proven and well understood technologies such as natural gas and nuclear power, to a resource mix of new technologies like inverter-based generation and storage. This includes intermittency issues related to renewable and distributed generation as well as how to handle excess generation during times when generation exceeds load, and challenging ramping issues often represented by the now widely known CAISO "duck

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6 Megan Cleveland, *States' Renewable Energy Ambitions* (February 4, 2019), *available at* http://www.ncsl.org/research/energy/states-renewable-energy-ambitions.aspx

curve." The growth of renewable energy as a proportionate share of SCE's power mix is also changing the timing and nature of load peaks on SCE's system and SCE must change the way it plans its system. These issues create operational risks and challenges for grid design. With the pace of technology change in conjunction with the transition to more renewable and DERs, including storage, this transformation creates risks for SCE's future transmission and associated distribution investments.

Moreover, many customers are increasingly expecting additional options in their power choices. These customers want to make their own decisions on what technology they will adopt (such as behind the meter solar panels and battery storage). As such, SCE must construct and manage a new type of grid. A grid that can, for example, not only deliver power to customers, but transport energy away from customers producing power ("two way power flows"), all while maintain grid reliability and safety for all customers. Designing, operating and maintaining this new grid, at the same time technology continues to offer customers more and more options, creates a new and growing challenge for SCE.

Q. How does pace of change create risks for SCE's investors?

A. The proliferation of DERs, including rooftop solar and distributed storage, calls into question the existing scope of the transmission business. Moreover, the role and use of transmission and distribution assets designed under past paradigms are evolving. The CAISO already has approximately 7,000MW of customer based roof-top solar within its Balancing Authority, and SCE has over 2,300MW within its territory.[7] These numbers continue to increase daily. Other technologies and innovations, such as distributed battery storage, energy efficiency, and advancements in demand response create further challenges to transmission and distribution planning.

These rapid changes in, and proliferation of, new technology creates risk for the traditional utility planning cycle. This in turn creates risks to investors. This risk is further increased by clean energy goals that will likely result in significant amounts of zero-marginal cost energy production that will impact the economic benefit analysis of new transmission projects. A transmission project deemed necessary today may be (and in recent cases in California has been) revisited and cancelled before it can go into service.

As the CAISO and stakeholders (including SCE) work to embrace these advancements, there will likely be uncertainty regarding whether transmission is needed for reliability, or whether alternatives to transmission, such as distributed storage or demand response, can substitute. With these shifts in technology comes risks, including risks impacting SCE's ability to earn a return on its investments, to collect costs related to abandoned projects in rates, and to meet customer load in a safe and reliable manner.

For example, in the 2016-2017 CAISO Transmission Plan,[8] the CAISO reassessed the need for the Gates-Gregg 230 kV transmission project –

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[7] California Distributed Generation Statistics, Dec. 31, 2018, https://www.californiadgstats.ca.gov/charts/ (reflecting data through Dec. 31, 2018).

[8] 2016-2017 Transmission Plan, *California ISO*, March 17, 2017, Board Approved, *available at* http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf.

previously approved in 2013 – based upon a lower energy and demand forecast resulting from behind the meter photovoltaic generation.[9] The CAISO found that the economic savings were not presently sufficient to justify the cost of the project and recommended that no further development action of the project be taken until its review was completed. In addition, in that same 2016-17 Transmission Plan,[10] the CAISO performed a review of previously approved projects as a result of changes in load forecasts and determined that thirteen other transmission projects were no longer required based on reliability and local capacity requirements, and deliverability assessments.[11] The CAISO's analysis included sensitivities with respect to behind the meter photovoltaic generation and additional achievable energy efficiency.

As another example, SCE's Coolwater – Lugo transmission project was cancelled in 2016[12] because the CAISO deemed the project unnecessary after reassessing its need several years into development. SCE had to abandon the project for reasons beyond its control, even though it had already incurred significant costs in attempting to license and develop the project.

A final recent example is SCE's Alberhill substation. SCE proposed building the Alberhill substation, which includes both the Commission and CPUC jurisdictional assets, in order to resolve overloading on SCE's distribution system and to address load growth in the area. On April 4, 2018, the CPUC issued a proposed decision denying the Alberhill Certificate of

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9 *Id.*, p.104.

10 *Id.*, p.104.

11 *Id.* at p. 102.

12 Dkt. ER16-1025.

Public Convenience and Necessity ("CPCN") based on the CPUC's conclusion that the project is not needed by 2021, if at all. The CPUC based its conclusion on recent successive forecasts from SCE and CAISO predicting lower load growth than the forecasts SCE and CAISO initially relied upon. Additionally, the CPUC concluded that with future battery storage potential "…there is no reason to expect anything other than a downward impact on peak demand."[13]

Given the rapid pace of industry changes and the time required for multiple jurisdictional approvals, significant environmental reviews, technological changes, and long licensing and permitting processes, SCE faces significant business risk. If transmission projects face changing industry conditions or changes in assumptions on economic value or load need, these investments can be postponed or cancelled. In other words, the usefulness of planned projects or those that are not yet completed are subject to substantial regulatory risks.

Q. Does California provide subsidies for distributed generation?

A. Yes. A significant subsidy exists for solar rooftop via Net Energy Metering ("NEM") rates. As an increasing number of customers install self-generation technologies, a larger part of SCE's fixed costs is avoided. Through NEM provisions and other state subsidy programs, customers who install self-generation technologies avoid certain transmission and distribution investment costs incurred by SCE on behalf of its customers, despite the fact that they continue to rely on the grid. Even though recent CPUC regulations require

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[13] CPUC, *Proposed Decision Granting Petition to Modify Permit to Construct the Valley-Ivyglen 115 kV Subtransmission Line Project and Denying Application for Certificate of Public Convenience and Necessity for the Alberhill System Project*, issued April 4, 2018, at pp. 32-33, *available at*http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M212/K643/212643589.PDF

such customers to pay certain non-bypassable charges moving forward, these charges are minimal and cost avoidance still occurs. When a certain category of customers avoids paying for the utility investments that are dedicated to their service, they are effectively shifting these costs to a smaller customer base. This trend will continue as the move from centralized generation to self-generation gathers more momentum, exerting upward price pressures on rates for customers without NEM.

Q. Do subsidies such as NEM create risks for SCE?

A. Yes. These subsidies result in cost shifts to customers that are not receiving the subsidy. For NEM, the fixed costs of SCE distribution and transmission are shifted to customers without NEM, resulting in higher rates to these customers. The subsidy in conjunction with higher rates that would otherwise apply encourages behavioral change, in this case by installing solar panels, to take advantage of the NEM subsides to avoid the otherwise increasing costs. In the end, fewer customers are forced to pay a greater share of SCE's fixed costs, making it increasingly difficult to recover such costs in rates.

Q. Do aging infrastructure and telecommunications systems, as well as cybersecurity risks, create more challenges and risks in integrating renewables and DERs into the grid?

A. Yes. SCE's electric system is aging and facing new strains in the form of outdated and slow telecommunications systems, and technology obsolescence. Many of SCE's distribution and lower voltage transmission facilities were installed during the high growth period after World War II. Replacing aging infrastructure is necessary but risky, particularly when the requirements that the electric system must meet are changing. SCE is also uniquely vulnerable to increasing cybersecurity risks due to greater numbers of distribution-connected devices and the specific technology required to manage the new grid architecture needed to accommodate DERs.

The rapid changes I previously described amplify the financial risks associated with replacing aging infrastructure. A project deemed necessary today may be revisited before it can go into service. As the State works to integrate 100% renewables, electrification of buildings and transportation, there will likely be uncertainty regarding whether transmission is needed or whether distribution and or storage provide a better alternative. With those shifts come risks, including those impacting SCE's ability to earn a return on its investments, collect costs related to abandoned projects in rates, and meet customer load. This creates risk for SCE's transmission and associated distribution investments.

IV. RISKS RELATING TO SCE'S ROLE IN PROCUREMENT

Q. **Please summarize risks related to SCE's energy procurement activities.**

A. To support California's ambitious environmental goals, SCE has substantial long-term power procurement contracts that are currently valued at billions of dollars above market value. These contracts create risks in a regulatory, legal and technological environment where the rate of change is accelerating. SCE is facing risks and uncertainty relating to California's procurement planning transition away from California's Long-Term Procurement Planning ("LTPP") process to the Integrated Resource Plan ("IRP") process. SCE is also facing risks and uncertainty relating to storage procurement, natural gas procurement and California's mandatory energy procurement programs. These risks are compounded by the uncertainty of how much load SCE must serve caused by

California's changing approach to retail electric competition and California's requirement that SCE remain the provider of last resort.

Q. Has SCE played a significant role in California's procurement policy?

A. Yes. To meet the energy and reliability needs of its customers and to help facilitate California's RPS and other goals, for the last decade SCE has entered into a significant number of long-term contracts. Many of the contracts were signed to provide the financial support needed to allow developers to build new clean resources to meet RPS goals. According to SCE's most recent "Change in Status" filing, the "Asset Appendix: Long-Term Firm Power Purchase Agreements (PPA)" shows over 11,000 MW of long-term firm power purchase agreements subject to the Commission's Market Base Rate (MBR) reporting requirements."[14] As of December 31, 2017 SCE reported contractual obligations for power purchase agreements of $39,877 million.[15]

Q. Has SCE recently quantified the current market value of these contracts?

A. Yes. As part of SCE's participation in the CPUC's Rulemaking 17-06-026, SCE estimated the above market costs of its current portfolio. This included both renewable (RPS) and conventional generation.

Q. What were the results of that analysis?

A. SCE determined its current procurement portfolio, overall, was priced significantly above market. That is, if SCE were to liquidate its portfolio, the

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[14] Dkt. ER10-1355-007, *SCE Notification of Change in Status (CIS) reported under ER10-1355-006*, filed Jan. 30, 2019.

[15] *Edison International and Southern California Edison, 2017 Financial & Statistical Report*, at p. 5, *available at* https://www.edison.com/content/dam/eix/documents/investors/sec-filings-financials/2017-financial-statistical-report.pdf

revenues generated from the sale would not cover the payments required under the contracts.

Q. Can you provide specific numeric results?

A. Yes, for example, looking at the contracted wind and solar in SCE's portfolio, from 2019 through 2035 the portfolio is estimated to have costs over $12 billion dollars above market value.

Q. Describe the risks that relate to the transition to the IRP process.

A. California is undergoing a significant procurement planning transition as it moves away from California's Long-Term Procurement Planning ("LTPP") process to the Integrated Resource Plan ("IRP") process. The IRP process was instituted by Senate Bill 350, known as the Clean Energy and Pollution Reduction Act of 2015 to "ensure that load serving entities (LSEs) meet targets that allow the electricity sector to contribute to California's economy-wide greenhouse gas emissions reduction goals."[16] LSEs, such as SCE, submitted their first IRPs in August 2018 and are awaiting a proposed decision on both individual LSE IRPs as well as plans for the system.

Because this is the first time the CPUC and LSEs have gone through the IRP process, and issues have been identified that require remedy in the 2019-2020 or future cycles, there remains significant uncertainty around future requirements for the IRP itself and impacts on procurement. For example, the CPUC has neither yet adopted, nor thoroughly studied, a system plan that aligns with the level of electric sector decarbonization, and transportation and

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[16] *See* CPUC, Integrated Resource Plan and Long Term Procurement Plan (IRP-LTPP), at http://www.cpuc.ca.gov/irp/

building end-use electrification, required for the state to achieve its statutorily-mandated economy-wide GHG reductions.

Further, several Community Choice Aggregation ("CCAs") noted that their IRPs filed with the CPUC did not represent their "real" IRPs, which may not be available for CPUC analysis or inclusion into the system plan.[17] The CPUC has acknowledged that the scope of its jurisdiction over CCA procurement is limited.[18] It is unclear what SCE's obligation will be if a CCA within its service territory fails to procure sufficient resources for system reliability or fails to meet its GHG reduction goals.

In addition, because of concerns that a host of energy providers (*e.g.*, DA, CCA) may not be able to secure the generation necessary to maintain electric grid reliability, the CPUC is exploring additional models for procurement. In particular, the CPUC has required workshops to discuss a "central procurement entity" to secure all local capacity needed for reliability. Within these workshops, the entity serving as the "central procurement entity" could be SCE. Under some possible frameworks, SCE would sign contracts, which will include capacity and potentially energy to serve the needs of CCA or DA customers, and then attempt to have end-use customers support their share of

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[17] *Comments of SCE on ALJ Ruling Seeking Comment on Proposed Preferred System Portfolio and Transmission Planning Process Recommendations*, R.16-02-007, filed Jan. 31, 2019, at p. 21; *Comments of SCE on Load-Serving Entities' Integrated Resource Plans*, R.16-02-007, filed Sept. 12, 2018, at pp. 7-11.

[18] CPUC Decision (D.)18-02-018, at p. 26 ("The [CPUC's] authority is primarily with respect to the planning process, in order to assess the aggregated impact of all of the LSE plans combined … As we note below, with some exceptions related to renewable integration resources, the procurement decisions, customers rates, and contract terms and conditions (outside of the RPS) are the domain of the CCA governing boards and not the [CPUC].").

the costs. This proceeding is on-going and it is unclear what changes to SCE procurement roles will ultimately result. However, it creates additional risk for SCE. Such an expansion of procurement requirements may impact SCE because rating agencies view some long-term procurement as "debt equivalents" when calculating certain financial metrics. And in general, additional procurement increases the risk of cost disallowance and cost recovery.

Q. Describe the risks that relate to storage procurement.

A. Additional risks are also prevalent with respect to the procurement of energy storage. SCE is on track to achieve its energy storage procurement target to procure 580 MW of storage by 2020.[19] However, much uncertainty remains in the energy storage space. For example, to date, the majority of energy storage procured by the California utilities has been lithium ion battery storage. The CPUC and other stakeholders have expressed interest in "whether policy should support a diverse set of technologies in the energy storage procurement activity of the [IOUs]."[20] The CPUC has not yet taken a position on the matter, but has created uncertainty on whether there will be additional energy storage procurement mandates to achieve technology diversity.[21] Further, stakeholders are pushing for more energy storage procurement mandates. For example, in response to a CPUC ruling asking questions about technology

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[19] CPUC Decision (D.)13-10-040 (implementing AB 2514).

[20] CPUC Decision (D.)18-10-036, at p. 24.

[21] *Id*. at p. 25 ("[T]his topic may be most appropriately suited for consideration in a potential future energy storage rulemaking.").

diversity, the California Energy Storage Alliance suggested the CPUC adopt a new Energy Storage Emerging Technology Procurement Plan that increases targets.[22]

Storage is a relatively new technology and procurement of new, and unproven, technology carries additional risks. The lack of a long-term track record for both the equipment and business models used to provide the technology creates risk that the technology may not perform as anticipated. The prospect of requirements to procure additional, potentially costly and unproven energy storage, particularly if the requirement does not align with CPUC-adopted use cases for energy storage, adds risk for SCE.

Q. Describe the risks that relate to gas procurement.

A. SCE procures significant amounts of gas to fuel its gas-fired generation facilities and thus has exposure to fluctuations in natural gas prices. In 2017, SCE spent approximately $308 million on natural gas purchase.[23] SCE also procures electricity from other suppliers who rely on the gas markets, so SCE has indirect exposure to gas market volatility through these transactions.

There are several current issues that have significant impacts on natural gas prices and create risk to SCE. First, there are gas system constraints in Southern California due in part to the response to 2015 problems at the Aliso Canyon Gas Storage Facility, as well as several other extended pipeline

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22 *Comments of the California Energy Storage Alliance to Assigned Commissioner's and Assigned Administrative Law Judge's Ruling Requesting Comments on Issues Pertaining to Energy Storage Technology Diversity*, Application (A.)18-03-002, filed Aug. 28, 2018, at pp. 6-10.

23 This amount is reflected in the Attachment D to each of SCE's 2017 CPUC Quarterly Compliance Reports, Advice 3595-E, Advice 3636-E, Advice 3683-E, and Advice 3735-E.

outages. These constraints have led to frequent Operational Flow Orders ("OFOs"), or orders to take certain actions to alleviate system conditions. The OFO typically carry a penalty price for gas imbalance outside of specified ranges – penalties that can exceed $25/mmbtu. Even the threat of such penalties has significant price impacts on gas, and in turn and power prices.

Since CAISO energy prices are frequently set by the marginal gas generator, spikes in gas prices can result in dramatic spikes in power prices. For example, in July of 2017, in part due to natural gas prices in Southern California reaching about $40/mmbtu, CAISO energy prices reached almost $1000/MWh. For the week of July 23, 2017, SCE estimated that high gas prices cost its customers an additional $150 million compared to average July prices.[24] Moreover, in part due to high gas prices, in 2018 SCE's procurement resulted in an undercollection of over $815 million (where procurement costs exceeded the amounts collected in rates) and SCE was required to file with the CPUC to increase rates.[25]

Given SCE's role in procurement, events that create material additional market costs tend to have negative customer and business impacts. High prices increase costs to customers and increase the risk of, and potential magnitude of, a disallowance to SCE and put additional pressures on regulators to reduce customer rates (in the short-term) by restricting needed investment in the utility.

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[24] *Joint Motion Of Southern California Edison Company (U 338-E) and Southern California Generation Coalition for Expedited Relief*, CPUC I.17-02-002, at p. 14 (filed Aug. 10, 2018).

[25] SCE Advice 3954-E to the CPUC, *Implementation of the Expedited Application of Southern California Edison Company Regarding Energy Resource Recovery Account Trigger Mechanism in Compliance with Decision 19-01-045*, submitted Feb. 15, 2019.

Q. Describe any relevant mandatory energy procurement programs that create risk for SCE.

A. SCE also has several mandated procurement programs — the Biofuel Renewable Auction Mechanism ("BioRAM"), the Renewable Market Adjusting Tariff ("Re-MAT"), and the Bioenergy Market Adjusting Tariff ("BioMAT"). All three of these programs are undergoing multiple modifications that will have impacts on SCE procurement. Although the scope and extent of the impacts are not yet clear, the uncertainty creates additional risk for SCE.

In sum, SCE's current role in procurement, and the uncertainty regarding how this role will evolve in light of the significant growth of customer options, creates an enhanced climate of risk for SCE.

Q. **Can you explain how debt equivalents from long-term purchase obligations impacts SCE?**

A. Rating agencies look at certain long-term purchases as equivalent to debt. While these purchases may not appear as debt on SCE's balance sheet, rating agencies create pro-forma financials where they increase the actual debt to reflect the contracts and change certain other measures.[26] Using the adjusted pro-forma financial statements, the agencies then calculate certain financial metrics such as funds from operations/interest, funds from operations/debt and

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26 California Public Utilities Commission Policy & Planning Division, *An Introduction to Debt Equivalency* (August 4, 2017), *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD%20-%20Intro%20to%20Debt%20Equivalency(1).pdf

debt/total capitalization. The results of these and other metrics help the rating agencies derive a utilities' credit rating. Debt equivalents negatively impact these ratios. This has a negative impact on the credit metrics and, at times, the credit rating of the utility.[27]

Q. Does SCE generate earnings from power trading?

A. No. SCE passes through all allowed procurement costs directly to customers without a profit mark up. If SCE "buys low" and "sells high," its customers may receive some benefit from a reduction in procurement costs, but SCE's shareholders do not profit from the transaction.

Q. Do CPUC cost recovery rules concerning procurement activities, including power, gas and other mandates, fully address risks associate with procurement?

A. No. While SCE continues to advocate for reasonable protections and cost recovery associated with its procurement, risk remains. Given the constantly evolving requirements, programs and new developments, rules are also constantly evolving via debate, creation, revision, application and interpretation. Rules that provide adequate protections today may be eroded by a decision tomorrow. Rules that SCE needs may be strongly and persistently opposed by differently situated parties that have a different view point or motivation. Given the billions of dollars SCE spends on procurement activities annually, and the tens of billions of contract obligations already committed,

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[27] Shannon Pratt and Roger Grabowski, The Lawyer's Guide to Cost of Capital: Understanding Risk and Return for Valuing Businesses and Other Investments, Chicago: ABA Publishing, 2014, pp. 401-403.

even minor rules inadequacies or changes to the rules can create material risks to investors.

Moreover, even assuming reasonable rules, the complex nature of such rules and their application to SCE's business will always be subject to varying interpretations. Intervenors may argue for outcomes or rule interpretations that run contrary to SCE's application or actual performance. Given SCE's vast amount of transactions, the large amount of administration and compliance activities associated with procurement, and the pure complexity of managing both the resource portfolio and the business processes, this creates a compliance risk associated with procurement that adds additional risk to the utility.

V. <u>RISKS RELATING TO CALIFORNIA'S APPROACH TO RETAIL ELECTRIC COMPETITION AND LOAD UNCERTAINTY</u>

Q. Describe the ways in which California's approach to retail electric competition creates risk to SCE.

A. There is a renewed policy shift towards customer choice and retail electric competition in California, as reflected by California's now expanding Direct Access program, its Community Choice Aggregation ("CCA"), and the growth of DERs. This creates business and regulatory risks for SCE that further amplify the risks relating to changes in grid design, operation and procurement. The president of the CPUC recently acknowledged these substantial risks by noting "we are deregulating electric markets through dozens of different decisions and legislative actions, but we do not have a plan. If we are not careful, we can drift into another crisis."[28]

Q. How else does Direct Access create risks for SCE?

A. California's Direct Access program allows a limited selection of consumers living in the state of California to purchase their electricity from an Electric Service Provider ("ESP"), instead of their utility. While utilities continue to provide customers with electric delivery related services, ESPs are competitive providers that provide alternative supply related products and services.

In 1996, California stood at the forefront of electric industry restructuring with new laws deregulating wholesale electricity generation and allowing competition through competitive ESPs rather than the utility (i.e., "Direct Access"). The flaws in these statutes became painfully apparent during the energy crisis of 2000-2001, as wholesale power prices rose to exorbitant levels. In response, the California legislature suspended Direct Access for additional customers and put in place a framework for California utilities to enter long-term power purchase agreements to ensure electricity supply to customers. Many of these contracts extend for up to 20 years over the life of generating plants and do not include "out" clauses that would protect SCE or its customers in the event of declining customer demand, changes in fuel availability, or falling power prices.

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[28] California Customer Choice, An Evaluation of Regulatory Framework Options for an Evolving Electricity Market (August 2018), at iii, *available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf*.

In 2010, Direct Access began increasing again due to legislation that required Direct Access to be phased back in over time, up to a cap.[29] In 2018, Governor Brown signed into law SB 237, which further expanded Direct Access' annual electricity cap, increasing the share of statewide load in the Direct Access market to about 15.5 percent.[30] The new law also requires the CPUC to submit a report to the state legislature by July 2020 on whether it should consider further re-opening the Direct Access program. It is unknown at this time whether the CPUC will, in its 2020 report to the legislature, recommend further re-opening of Direct Access. This uncertainty makes it difficult for SCE to forecast the size of its customer base and the amount of bundled service load for which it must procure and generate electricity.

Direct Access presents significant risks to California utilities, particularly if existing rules and regulations surrounding utility cost recovery are not implemented properly. While SCE views existing legislation and other rules as providing for cost recovery, the long-term nature of these power purchase agreements combined with a renewed policy shift towards deregulation leaves SCE with the risk that cost pressures could lead to legislative or regulatory policy changes to the regulatory compact (i.e., assurance of recovery of reasonably incurred costs in exchange for ongoing regulation). In addition, it creates significant risks because utilities, including SCE, are required to remain providers of last resort. That is, customers can choose (or be forced by the

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[29] CPUC Decision (D.)10-03-002, issued March 15, 2010, at Appendix 1.

[30] *How a New California Law Will Expand the State's Competitive Energy Market* (Oct. 3, 2019), https://www.greentechmedia.com/articles/read/california-law-will-expand-direct-access-market#gs.YnZlpsrF.

current energy provider) to return to SCE at any time. At which time, SCE has an obligation to provide these customers power. And, while rules exist that should allow cost recovery for SCE in its role as a POLR, the magnitude of departing load and in turn the possibility of its rapid return back to SCE create a situation that has never been fully tested. This back-stop role to support retail access and competition, and the potential impacts (both foreseeable and unknown) it may have on SCE, creates additional risk to SCE's investors.

Q. How does CCA create risks for SCE?

A. California utilities are also seeing a large number of customers departing to be served by CCAs. CCA permits customer groups, including cities or counties, acting alone or in purchasing groups, to procure electricity directly from wholesale non-utility suppliers. The utility continues to provide distribution services, billing, and metering. Much like Direct Access, the potential for CCA affects SCE's ability to reliably predict the size of its customer base and the amount of bundled service load for which it must procure or generate electricity, adding to the risks of committing to longer-term resources. At the end of 2018, 4% of load in SCE's territory was served by CCAs.[31] However, this has already materially increased in 2019, and is expected to continue to increase rapidly. The CPUC recently estimated that up to 85% of historical retail load served by the California electric utilities could depart for alternative procurement service by the mid-2020s.[32] And, there are no caps on the

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[31] Based on 12-month sales ending December 2018 as a percent of 2018 retail sales.

[32] CPUC Staff White Paper, *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*, p. 3 (May 2017), *available at*

amount of load CCA providers can serve. For example, PG&E forecasts 54% of its load will be served by CCA, Direct Access or BART by the end of 2019.[33] This structure provides little certainty around the flow of customers to and from CCAs. Once a customer is served by a CCA, they can opt out at any time and return to SCE's service. In addition, a CCA could cease providing service at any time and the customers would return to SCE service without much, if any, warning. Similar to Direct Access, SCE must continue to serve as the provider of last resort. As a result, SCE faces the risk of making procurement – whether in response to legislative or CPUC mandates or based on load forecasts – that may ultimately become unnecessary in light of departing load. All this uncertainty adds risk to SCE's long-term procurement, risk of ultimate recovery of procurement cost, and risk of providing services for very material and unexpected returning load. And again, these risks are born by SCE's investors.

Q. Given the potential for a significant amount of load departure, has the CPUC fully resolved risks to SCE surrounding load migration from CCAs and Direct Access?

A: No. In addition to the uncertainty around load that SCE will serve, and the procurement needed, additional risks remain related to cost shifting. The Power Charge Indifference Adjustment ("PCIA") is "the mechanism to ensure that the customers who remain with the utility do not end up taking on the

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http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf.

[33] California Energy Commission, Dkt. 18-IEPR-04 https://efiling.energy.ca.gov/GetDocument.aspx?tn=224108.

long-term financial obligations the utility incurred on behalf of now-departed customers," such as utility expenditures to build power plants and long-term power purchase agreements.[34] The CPUC recently adopted a revised PCIA methodology, including an annual true-up mechanism and cap.[35] This decision also opened a second phase of the CPUC's PCIA rulemaking to consider utility portfolio optimization, to establish a process for ESPs (i.e., Direct Access) or CCAs choosing to prepay their PCIA obligation, to develop the true-up process for the market price benchmarks used to calculate the PCIA, and to consider other potential issues related to the PCIA.[36] While D.18-10-019 provides some certainty in terms of a revised PCIA methodology that provides a greater likelihood that SCE's bundled service customers will remain indifferent to departing customers, uncertainty remains around how accurate the true-up process will be, what impact the cap will have, and what potential portfolio optimization measures the CPUC will require SCE to implement. Until these issues are resolved in Phase 2 of the CPUC's PCIA rulemaking, and depending on how they are resolved, SCE is exposed to significant uncertainty and risk regarding procurement and load migration to and from the utility.

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34 *See* http://www.cpuc.ca.gov/PCIA/ (*last visited* April 10, 2019).

35 CPUC Decision (D.)18-10-019.

36 CPUC Decision (D.)18-10-019 at pp. 111-119, Ordering Paragraph No. 14.

VI. RISKS RELATING TO REGULATORY LAG

Q. Please explain regulatory lag and how much of it SCE is facing.

A. Regulatory lag is a delay beyond a regulatory/statutorily anticipated time period which introduces uncertainty in a regulatory outcome. Edison Electric Institute ("EEI") has reported that regulatory lag – as defined as the time between filing a case and a decision - in General Rate Cases across all utilities in the United States averages about 10 months.[37] SCE's 2015 GRC was issued 11 months after the start of the test year (where the test year is the year the rate is intended to go into effect), and SCE's 2018 GRC is still pending, at the time of this filing, over 15 months since the start of the test year. Using EEI's metric, this would constitute a 25 month delay for the 2015 GRC and at least a 29 month delay for the 2018 GRC.

Test Year	**Decision Date**	**Delay After Start of Test Year**	**Delay Per EEI Metric**
2006	May 11, 2006	4.3 months	~17 months
2009	March 12, 2009	2.3 months	~16 months
2012	November 29, 2012	10.9 months	~24 months
2015	November 5, 2015	10.1 months	~24 months
2018	After April 10, 2019	451+ days / 14.8+ months	29+ months

[37] *Edison Electric Institute Rate Case Summary Q4 2017 Financial Update*, at pp. 3-4, http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Documents/QFU_Rate_Case/2017_Q4_Rate_Case.pdf

While SCE appreciates the significant staffing and budgetary constraints the CPUC staff face in processing the GRC, and the complexity of issues that must be addressed in the context of California's ambitious policy objectives, this data demonstrates that regulatory lag in California is greater than other states thus causing greater regulatory risk for SCE as a California utility.

Q. What risk does regulatory lag create?

A: While a delayed GRC decision in California may not impede SCE's ability to recover a full year's revenue requirement, it does create risks. For example, SCE budgeted its 2018 capital expenditures and expenses and incurred most of the associated costs without knowing what the CPUC will ultimately authorize for the year. If SCE guesses wrong on the overall spending the CPUC will ultimately approve in the 2018 GRC decision, it will not be able to remediate this overspend, given that the test year has come and gone. This risk is heightened in SCE's 2018 GRC, which seeks recovery for unprecedented levels of infrastructure expenditures to modernize the electric grid to support California's environmental policy goals and industry transformation. This means investors are at risk for the spending decisions SCE has had to make in the absence of CPUC authorization. Investing billions in capital without budgetary guidance from a GRC is an example of regulatory lag that results in substantial regulatory risk to investors.

This regulatory lag risk is exemplified by SCE's' Equipment Demonstration & Evaluation Facility ("EDEF") program, which was included in its 2015 GRC. The Proposed Decision, which denied the EDEF funding, was not issued until September of the 2015 test year. The CPUC's final decision, which ultimately adopted the reductions found in the Proposed

Decision, was not issued until November 5, 2015. SCE did not anticipate any disallowance of funding, since the request was unopposed. So, SCE proceeded with constructing EDEF, and incurred expenditures on the EDEF program consistent with the proposals in its 2015 GRC application. As of December 2015, SCE had already spent $5.2 million on EDEF. In this example, the fact that a memorandum account was established for test year 2015 did not protect SCE from disallowance due to a rate case decision that extended well into the test year. The ultimate recovery of these funds remains undetermined.

VII. RISKS RELATING SPECIFICALLY TO SCE'S TRANSMISSION ASSETS

Q. Are there any other risks that are specific to SCE's transmission assets and should also be considered in setting its cost of capital?

A. Yes. While SCE's cost of capital is a function of its overall enterprise risk as perceived by investors, there are some identifiable components of that risk that are directly related to its transmission assets and the services they provide to wholesale and retail customers. Because this is a proceeding intended to ensure SCE an adequate return on its transmission investment, it is appropriate to highlight the risks unique to that investment. These transmission-specific risks can create a disincentive for additional transmission-related capital expenditures. Providing a fully-compensating return counters this disincentive, and also ensures that SCE's transmission customers pay for the effect of risks directly attributable to the service they are using.

Q. Please describe the risks currently associated with the ownership of transmission assets.

A. First, there are generic transmission risks which probably affect all owners given the movement toward electric utility deregulation and Transmission Organizations.[38] Second, there are certain risks unique to the California electricity market and uncertainty associated with actions taken by the CAISO.

Q. Describe transmission-related risk from an industry-wide perspective.

A. Operation of much of the electric transmission networks throughout the United States has been transferred from utility owners to independent entities. Utilities in California, New York, the Pennsylvania-New Jersey-Maryland area, New England, the Midwest, Texas, and parts of the Southwest have joined Transmission Organizations. Congress indicated its support for the further development of Transmission Organizations in the Energy Policy Act of 2005. There are risks associated with this structure.

First, whenever asset ownership is separated from operational control, there is an increased risk that the asset owner will face unanticipated costs due to actions taken by the entity with operational control. The entity charged with control will have smooth operations and reliability as its objectives and will not face the cost consequences of its decisions. As a non-profit corporation, the CAISO has been allowed by the Commission to pass on its costs to Participating Transmission Owners ("PTOs"), including SCE, with no

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[38] Unless otherwise indicated, "Transmission Organization" refers to "a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities." Federal Power Act §215(a)(6), 16 U.S.C. §824o(a)(6), enacted by Energy Policy Act of 2005, §1211(2005).

assurance that the PTOs have the ability to recover these costs from customers. Second, based on SCE's experience with the CAISO, independent system operators will run the transmission system differently from the way it was run when it was under the control of an integrated utility. SCE's transmission system was originally built for bundled utility dispatch primarily to serve SCE's retail customers. Now it is being used to support market dispatch of unbundled and deregulated wholesale generation. Broadly speaking, transmission assets will be utilized more aggressively when the operator is trying to accommodate the needs of many users, and that will affect operation and maintenance of the transmission system.

Q. What are some additional transmission-related risks that SCE faces?

A. SCE's transmission assets have been under the CAISO's operational control for nearly twenty years. Many of the generic risks described above have materialized as actual costs in California. Some may be the result of anomalies unique to the California market, while others are probably unavoidable given the separation of transmission operation from ownership.

The CAISO has in the past proposed tariff amendments or discussed proposal that allocated costs to Scheduling Coordinators (as defined in the CAISO Tariff) and Transmission Owners, such as SCE, without ensuring that such costs were in turn recoverable from customers and/or without providing a clear indication of who should ultimately bear these costs. For example, the CAISO's original rules concerning congestion cost responsibility for Existing Transmission Contracts did not allow SCE to collect all costs.[39] Other

[39] This issue was not resolved until the CAISO implemented its nodal market proposal as filed in Dkt. ER06-615.

proposal have been discussed that would hold the Transmission owner responsible for congestion and other market uplift costs associated with transmission outages.[40] In the ensuing Commission litigation, the staffs of SCE's regulators and SCE's various customer classes are often at odds with one another, increasing the likelihood that SCE will be unable to recover the costs.

Lawsuits or complaints against the CAISO for negligence, tariff violations, or other wrongdoing could result in costs for Scheduling Coordinators and PTOs such as SCE because of the CAISO's non-profit status. Another concern is that CAISO Tariff and Transmission Control Agreement provisions greatly limit the CAISO's liability.

VIII. SCE PARTICIPATION IN THE CAISO

Q. Does participation in the CAISO provide economic efficiencies, more efficient asset utilization and reliability benefits to SCE's customers when compared to SCE's operations prior to joining the CAISO?

A. Yes. The CAISO has implemented a host of tariff rules and other procedures aimed at increasing the economic efficiency of grid and market operations, and enhancing reliability. Of note, the CAISO runs California-wide co-optimized markets for energy and ancillary services based on a security constrained dispatch. This allows the CAISO to optimize and minimize costs, based on the bids submitted by suppliers, to meet its energy needs in a reliable manner. Moreover, the CAISO has expanded its real-time market to include additional

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[40] For example, page 12 of the 2015 Stakeholders Initiative Catalog includes a suggestion to allocate CRR shortfalls due to transmission outages to Transmission Owners. *See* 2015 Stakeholder Initiatives Catalog, Jan. 23, 2015, http://www.caiso.com/Documents/Final_2015StakeholderInitiativesCatalog.pdf

States. The CAISO reports that, since the inception of this Energy Imbalance Market in November of 2014, participants have received over $564 million in gross benefits.[41] This degree of regional market optimization was not possible when SCE was a stand-alone balancing authority.

The CAISO also fully optimizes use of its transmission by modeling physical electrical flows, as opposed to arbitrary "contract path" utilization used at times by SCE in the past. By modeling physical flows, the CAISO fully utilizes all available transmission capacity while respecting reliability constraints such as flow limits, voltage support and the need to operate in a consideration of contingencies. In conjunction with its energy markets, the CAISO can efficiently resolve transmission congestion, ensuring that the most economically beneficial resources receive access to the transmission system. Moreover, through CAISO's the Congestion Revenue Rights (CRR) process, the CAISO provides market participants a financial tool, as well as multiple auction processes, to help participants manage congestion costs. Again, this degree of regional transmission optimization was not possible when SCE was a stand-alone balancing authority.

The end result of these CAISO process is improved market economics, improved asset utilization and improved reliability.

Q. Does SCE's participation in the CAISO provide other benefits to customers?

A. Yes. For example, though its Commission-jurisdictional tariffs, the CAISO has implemented numerous policies and practices that benefit the CAISO grid

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[41] *Western EIM Benefits Report*, Fourth Quarter 2018, https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ4-2018.pdf

and its customers. Significantly, the CAISO has led the nation in implementing Order 1000, which allows for competitive transmission in the CAISO footprint, increasing competition with the objective of reducing costs. Further, the CAISO has a robust transmission planning process that annually evaluates proposals to efficiently develop transmission projects to meet reliability, economic and policy objectives.

Further, the CAISO, through its Department of Market Monitoring, continuously monitors energy and related markets. Additionally, the CAISO, through its tariff mechanisms implements market power mitigation when appropriate, and provides stakeholders a wealth of information on market performance, grid conditions and other items to improve the transparency and efficiency of their markets and grid operations for the benefit of customers. And while participation in the CAISO also creates additional risks to SCE, including those noted above, the benefits to customers of continued CAISO membership are numerous. Therefore, SCE's continued membership in the CAISO should be incentivized.

Q. Does this conclude your testimony?

A. Yes.

DECLARATION

I, Gary A. Stern, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 10, 2019 in Rosemead, California

Gary A. Stern

Gary A. Stern

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF FRANK GRAVES

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-22)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)))**	**Dkt. No. ER19-______-000**

SUMMARY OF THE PREPARED DIRECT TESTIMONY OF FRANK GRAVES

(EXHIBIT SCE-22)

Mr. Graves's testimony and report (Exhibit SCE-24) discuss the extreme risks and potential uncompensated cost recovery liabilities faced by Southern California Edison ("SCE") and other investor-owned utilities from recent megafires in California. The report describes trends in the frequency, size, and costs of large California fires and the implications that can be drawn about the amounts of additional compensation that equity investors would need, above and beyond the normal cost of equity allowance, in order to bear different degrees of exposure to liability for property damages from wildfire costs.

Mr. Graves explains the somewhat counterintuitive nature of "asymmetric risks" like wildfires and why they need to be specially compensated. He also provides a menu of levels of costs for the asymmetric risk SCE now faces related to megafires under California's policy of inverse condemnation, when property damages arise from fires in which utility equipment played a role. Mr. Graves concludes that an ROE allowance of 600 basis points added to SCE's allowed ROE would be commensurate with the apparent size and insurance cost of the wildfire problem.

Mr. Graves's testimony also demonstrates that this 600 basis point increase is unlikely to fully compensate SCE for the entire range of risk posed by wildfires. Mr. Graves concludes that any ROE increase will still leave a residual risk concentrated on current shareholders under some circumstances if or when those allowances, even accumulated over time, do not match the immediate realized burden from a megafire. He explains that it is very important to realize that the inverse condemnation policies of California essentially force the utilities to be acting like insurance agencies, when they are not in fact structured like them in terms of diversity of risk exposures or financial structure and capabilities, nor is insuring against such risks their primary responsibility. He concludes that a supplemental ROE allowance would therefore be helpful and appropriate under current circumstances to provide some compensation that increases their likelihood of viability after damages from a large fire, but it will not cover all foreseeable problems, and it is not an approach for compensation, or for fire control planning, that is suitable for the long run.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
FRANK GRAVES
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name, business address, employer, and title for the record.

A. My name is Frank C. Graves. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal of The Brattle Group ("Brattle") and member of its utilities practice, called the Regulated and Energy Markets Group.

Q. Please describe your qualifications and experience.

A. I have been a consultant to the electric and gas industries for over 35 years, having provided planning advice and testified in many jurisdictions on a wide variety of matters related to resource planning, service pricing, financial risk, prudence, and cost recovery. My academic training was focused on finance and mathematical modeling at Massachusetts Institute of Technology, where I received a Master of Science degree in Management in 1980. A full description of my background and qualifications in a resume containing the details of my career experience and publications is included as Exhibit SCE-23.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Federal Energy Regulatory Commission ("FERC" or "Commission") a white paper prepared by myself and my colleagues at Brattle discussing the extreme risks and potential uncompensated cost recovery liabilities faced by Southern California Edison ("SCE") and other investor-owned utilities from recent megafires in California. A copy of the white paper is included as Exhibit SCE-24. The report describes trends in the frequency, size, and costs of large California fires (megafires) and the implications that can be drawn about the amounts of additional compensation that equity investors would need, above and beyond the normal cost of equity allowance, in order to bear different degrees of exposure to liability for property damages from wildfire costs.

Q. How is this white paper relevant to this FERC proceeding specifically?

A. There are two ways. First, it explains the somewhat counterintuitive nature of "asymmetric risks" like wildfires and why they need to be specially compensated. Second, it provides a menu of levels of costs for the asymmetric risk SCE now faces related to megafires under California's policy of inverse condemnation for property damages arising from fires in which utility equipment played a role. These provide the basis for SCE's decision to seek an extra 600 basis points of return on equity ("ROE") in this proceeding.

Q. Please briefly describe the distinction between asymmetric and normal financial risk.

A. Business risks are normally defined in terms of situations and conditions that could cause a company to be either more or less profitable than expected, depending on how future uncertainty is resolved. For potential liability from wildfire property damage, there is no two-sided possibility of gain or loss: There is either normal profitability if there are no fires or fire liabilities, or worse than expected profitability if there are fires for which SCE is assigned unrecoverable property damage costs. Unlike normal business risks, asymmetric risks are generally not reflected in conventional measurements of a utility's cost of equity, even though they can be large and important. Instead, they create an impairment in the utility's opportunity to earn a fair return and can even threaten its financial integrity. They are more like an insurance cost that must be measured and compensated directly (or otherwise mitigated). My report provides an extensive discussion of why it is the case that such a large financial problem as megafire cost exposure might not be priced into the observed cost of capital.

Q. Please give an overview of the empirical aspects of your report that evaluate the cost of this risk.

A. To quantify the ROE supplement SCE would need to compensate for its apparent exposure to these asymmetric risks, we first look at potential loss sizes as revealed from the history of property damages from California megafires, including information on a few hundred of them recognized in SCE's recent Risk Assessment and Mitigation Phase ("RAMP") proceeding at the California Public Utilities Commission. This data shows utility-associated fires ranging up to several billions of dollars in property damages, which when evaluated statistically by SCE indicate a "tail event" wildfire loss exposure of about $1.4 billion. This is the average pre-tax cost of the worst 10% of predicted wildfire damages modeled in their RAMP filing.

As a second basis for quantifying the exposure, the report describes how we augmented the RAMP fire data with costs from a few additional late 2017 and 2018 events that had not occurred at the time of SCE's RAMP analysis. We apply the Monte Carlo methods of risk analytics from SCE's RAMP filing to this augmented data and then evaluate its range of costs with California wildfire-specific insurance pricing data using two approaches: (i) prices prevailing in the catastrophe bond market, and (ii) public information on recent utility fire insurance policy costs. These approaches shows that exposure to this entire distribution of risks (after about $1 billion of fire insurance SCE already has in place) has a likely after-tax annual cost (including the assumption that any fire damage expenses would be deductible and fully offset by taxable income) of around $1 billion—albeit with considerable uncertainty over the possibility that that amount could be too low.

Q. How does this analysis relate to SCE's request for a 600 basis point ROE supplement?

A. These analyses lead to the conclusion that an ROE allowance of 600 basis points added to SCE's allowed ROE (equivalent to $1 billion per year of net income against SCE's roughly $18 billion equity portion of rate base) would be commensurate with the apparent size and insurance cost of the wildfire problem. Authorizing such an amount on top of the cost of equity (measured in conventional ways and reflecting risk positioning in the industry) would provide additional investor returns needed to account for the severe wildfire risk SCE faces.

Q. Does this wildfire risk ROE fully compensate for the entire range of risk?

A. No, probably not. Although the underlying calculations address the apparent full range as it is now understood, it is unlikely that the required ROE increase can be estimated and calibrated accurately to offset the potential cost of megafires. Modest changes in assumptions or sample data sources about the size or frequency of fires can change the results considerably, with 600 basis points being simply in the middle of a large range. In addition, essentially any ROE increase will still leave a residual risk concentrated on current shareholders under some circumstances if or when those allowances, even accumulated over time, do not match the immediate realized burden from a megafire. It is very important to realize that the inverse condemnation policies of California essentially force the utilities to act like insurance agencies, when they are not in fact structured like them in terms of diversity of risk exposures or financial structure and capabilities, nor is insuring against such risks their primary responsibility. A supplemental ROE allowance would therefore be helpful and appropriate under current circumstances to provide some compensation that increases their likelihood of viability after damages from a large fire, but it will not cover all foreseeable problems, and it is not an approach for compensation, or for fire control planning, that is suitable for the long run.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

DECLARATION

I, Frank Graves, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the same questions appearing therein, my answers would, under oath, be the same.

Executed on April 9, 2019 in Boston, Massachusetts.

Frank Graves

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Frank C. Graves

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
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EXHIBIT SCE-23

EXHIBIT TO THE TESTIMONY OF
MR. FRANK GRAVES

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

FRANK C. GRAVES

Principal

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Mr. Frank C. Graves is a Principal of The Brattle Group who specializes in regulatory and financial economics, especially for electric and gas utilities, and in litigation matters related to securities litigation, damages from breached energy contracts, and risk management.

He has over 35 years of experience assisting utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, fuel and gas supply procurement and hedging, pricing and cost recovery mechanisms, cost and performance benchmarking, renewable asset selection and contracting, and new business models for distributed energy technologies. He has testified before many state regulatory commissions and the FERC as well as in state and federal courts and arbitration proceedings on such matters as integrated resource planning (IRPs), energy contract disputes, the prudence of investment and contracting decisions, risk management, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions.

In the area of financial economics, he has assisted and testified in civil cases in regard to contract damages estimation, securities litigation suits, special purpose audits, tax disputes, risk management, and cost of capital estimation, and he has testified in criminal cases regarding corporate executives' culpability for securities fraud.

He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

AREAS OF EXPERTISE

- Utility Planning and Operations
- Regulated Industry Policy and Restructuring
- Energy Market Competition
- Electric and Gas Transmission
- Financial Analysis and Commercial Litigation

PROFESSIONAL AFFILIATIONS

- IEEE Power Engineering Society
- Mathematical Association of America
- American Finance Association

REPRESENTATIVE ENGAGEMENTS

Utility Planning and Operations

- Uncertainty over the pace and extent of potential distributed energy resources (DERs) adoption by customers makes load forecasting and system planning much more complex, possibly involving future "tipping points" when DER use could accelerate rapidly. However, statistical histories on these improving technologies are not yet very informative as to when or why such a shift might occur. Mr. Graves has assisted several distribution utilities with a new, behavior-based modeling technique for long range system planning that simulates possible paths to DER adoption, utilizing system dynamics methods that recognize the feedbacks between offered electricity prices, customers' propensities to use DERs, declining technology costs, cost shifting to non-users, and other interdependencies.
- Many large high-tech firms are selling power supply services relying entirely on renewable resources. This can only be done for average or cumulative power needs, but the resulting green energy production will not match the time pattern of those firms' demand. Mr. Graves lead a team evaluating how much risk is borne by a utility from offering such service over many years, when it will have to balance the green supply (such as rooftop solar) against its own load and the regional market.
- As distributed energy resources (DERs) become more economical and more widely adapted by retail electricity customers, the sustainability of the traditional cost-of-service business model for utilities has become questionable. To help utilities anticipate and accommodate these technology changes, Mr. Graves as lead the development of long term distribution planning models based on System Dynamics simulation methods. This approach created simulations based on dynamic feedbacks between utility policies and customer behavior, providing a new perspective on how much and how fast the "utility of the future" must evolve.
- Many utilities are facing a concern through the expected useful lives of their coal plants are being shortened by low gas prices and increased use of renewables. Mr. Graves helped a utility justify early retirement of a coal plant with full recovery of its stranded costs, when that plan could be replaced more economically with new wind plants while the tax incentives for their development were still in effect.
- Mr. Graves developed a valuation and risk analysis model showing that a utility's RFP for new generation could be better served by deferring new plant construction for a few years via a less costly and less risky transitional market-based power supply contract with price and quantity terms shaped to match the shifting needs over time until supply shortfalls were large enough to justify the investment in a new power plant at efficient scale. The parties negotiated a multi-year contract along these lines in lieu of pursuing the construction alternative that initially came out of the RFP selection.
- In Maryland the electric distribution companies administer SOS (Standard Offer Service) supply procurement and accounting to backup customers who do not use a competitive

retail power supplier. The utilities are authorized to recover both the direct and financing costs of that service plus a return on equity. Mr. Graves developed a method for sizing an appropriate equity return for the SOS risks and administrative services based on analogies to various intermediation businesses on the internet, such as EBay, PayPal, and others—in which, like SOS intermediation, the businesses do not take ownership for the products conveyed. Testimony was provided.

- Mr. Graves co-lead a team of Brattle analysts to assess the relative influence of different factors that were affected by the "Polar Vortex" cold snap of early 2014 that caused dramatic spikes in local power and gas prices in parts of the mid-Atlantic and northeastern US. The risks of similar recurring events were assessed in light of pending expansions of the electric and gas transmission grids, as well as likely coal plant retirements.
- For the Board of Directors or executive management teams of several utilities, Mr. Graves has lead strategic retreats on disruptive issues facing the electric industry in the future and how a utility should choose which risks and opportunities to embrace vs. avoid.
- Air quality and other power plant environmental regulations are being tightened considerably in the period from about 2014-2018. Mr. Graves has co-developed a market and financial model for determining what power plants are most likely to retire vs. retrofit with new environmental controls, and how much this may alter their profitability. This has been used to help several power market participants assess future capacity needs, as well as to adjust their price forecasts for the coming decade.
- Successful merchant power plant development and financing depends in part on obtaining a long term power purchase agreement. Mr. Graves directed a study of what pricing points and risk-sharing terms should be attractive to potential buyers of long-term power supply contracts from a large baseload facility.
- Many utilities are pursuing smart meters and time-of-use pricing to increase customer ability to consume electricity economically. Mr. Graves has led a study of the costs and benefits of different scales and timing of installation of such meters, to determine the appropriate pace. He has also evaluated how various customer incentives to increase conservation and demand response might be provided over the internet, and how much they might increase the participation rates in smart meter programs.
- Wind resources are a critical part of the generation expansion plans and contracting interests of many utilities, in order to satisfy renewable portfolio standards and to reduce long run exposure to carbon prices and fuel cost uncertainty. Mr. Graves has applied Brattle's risk modeling capabilities to simulate the impacts of on- and off-shore wind resources on the potential range of costs for portfolios of wholesale power contracts designed to serve retail electricity loads. These impacts were compared to gas CCs and CTs and to simply buying more from the wholesale market to identify the most economical supply strategy.
- For a municipal utility with an opportunity to invest in a nuclear power plant expansion, Mr. Graves lead an analysis of how the proposed plant fit the needs of the company, what

market and regulatory (environmental) conditions would be required for the plant to be more economical than conventional fossil-fired generation, and how the development risks could be shared among co-owners to better match their needs and risk tolerances. He also assessed the market for potential off-take contracts to recover some of the costs and capacity that would be available for a few years, ahead of the needs of the municipal utility.

- The potential introduction of environmental restrictions or fees for CO2 emissions has made generation expansion decisions much more complex and risky. He helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coal plant.
- Mr. Graves helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement, and the resulting impact on the range of potential customer costs.
- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including how to build and value contingency plans in their resource selection criteria, and what kinds of regulatory communications to pursue to manage expectations in this difficult environment.
- For a Midwestern utility proposing to divest a nuclear plant, Mr. Graves analyzed the reasonableness of the proposed power buyback agreement and the effects on risks to utility customers from continued ownership vs. divestiture. The decommissioning funds were also assessed as to whether their transfer altered the appropriate purchase price.
- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.
- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a result,

nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared developed an economic model of the performance that could have reasonably been expected of the government, had it not breached its contract to remove the spent fuel.

- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.
- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company's rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.
- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.
- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.
- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.
- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have

been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.

- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. Alternative balancing valuation and accounting methods were shown to be cheaper, more efficient, and simpler to administer. This analysis helped the parties reach a settlement based on a cash-in/cash-out design.
- The Clean Air Act Amendments authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.
- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.
- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.
- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.

- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses to identify resale opportunities by comparing the marginal operating costs of all this company's power plants not needed to meet target reserves to the marginal costs for almost 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.
- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.
- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe "front end load" while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This "value of service" framework was generalized for the Electric Power Research Institute.
- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.
- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.
- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.
- For a Midwestern electric utility, Mr. Graves extended a regulatory pro forma financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to

completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).

- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.
- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial pro forma simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.
- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

Regulated Industry Policy and Restructuring

- Several states and cities have set goals of deep decarbonization of their local economies, often dubbed "80 by 50" if they aspire to 80% reductions in GHG emissions by 2050. Achieving this will involve radical change in the economy of those regions, potentially with dramatic load growth due to electrification and massive investment in new infrastructure for end-use and power supply and delivery. Mr. Graves has built models that show what types and degree of change could arise, and what they might cost depending on how such transformations are incentivized or enforced.
- As wholesale power and natural gas prices have fallen, interest in "retail choice" for energy supply has increased. At the same time, some state regulatory agencies have become concerned that misleading marketing and non-competitive pricing are too common in the mass market, especially afflicting low income and senior residential customers. Mr. Graves lead a review of such concerns that compared practices and market performance in several states to identify what could be done to improve such services.
- For a group of utilities responding to a state mandate to consider means of encouraging distributed technologies to be assessed and incentivized in parity with central station generation, Mr. Graves and others at Brattle prepared alternative means of incorporating marginal cost and externality value considerations into new cost/benefit assessment tools, procurement mechanisms, and supply contracting.
- For a mid-Atlantic gas distribution utility, Mr. Graves assessed mark to market losses that had occurred from gas supply hedges entered before spot prices declined precipitously.

Concerns were voice that this outcome indicated the company's hedging practices were no longer attune to market conditions, so Mr. Graves developed and lead workshop between the company, intervener groups, and state commission staff to define new appropriate goals, mechanisms and review standards for revised risk management approach.

- For a major participant in the Japanese power industry contemplating reorganization of that country's electric sector following Fukushima, Mr. Graves lead a research project on the performance of alternative market designs around the US and around the world for vertical unbundling, RTO design, and retail choice.
- For several utilities facing the end of transitional "provider of last resort" (or POLR) prices, Mr. Graves developed forecasts and risk analyses of alternative procurement mechanisms for follow-on POLR contracts. He compared portfolio risk management approaches to full requirements outsourcing under various terms and conditions.
- For a large municipal electric and gas company considering whether to opt-in to state retail access programs, Mr. Graves lead an analysis of what changes in the level and volatility of customer rates would likely occur, what transition mechanisms would be required, and what impacts this would have on city revenues earned as a portion of local electric and gas service charges.
- Many utilities experienced significant "rate shock" when they ended "rate freeze" transition periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have led to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.
- The impacts of transmission open access and wholesale competition on electric generators risks and financial health are well documented. In addition, there are substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves co-authored a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.
- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms, hedging strategies, and associated regulatory guidelines

that clarify the conditions for approval and cost recovery of resource plans, in order to make possible the expedited procurement of power from wholesale market suppliers.

- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.
- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for a utility's fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.
- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundlings that were insensitive to system operations.
- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.
- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and they have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Market Competition

- Mr. Graves assisted a nuclear plant owner with an assessment of whether a proposed merger of a company in whom it had a partial investment interest would alter the co-owner's incentives to manage the plant for maximum stand-alone value of the asset. Structural and behavioral models of the relevant market were developed to determine that there would be no material changes in incentive or ability to affect the value of the asset.
- Mr. Graves has testified on the quality of retail competition in Pennsylvania and on whether various proposals for altering Default Service might create more robust competition.
- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC's Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.
- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.
- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.
- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.
- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made adequate competition among numerous generation suppliers very implausible.

- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Electric and Gas Transmission

- Substantial fleets of wind-based generation can impose significant integration costs on power systems. Mr. Graves assisted in assessing what additional amounts and costs for ancillary services would be needed for a Western utility with a large renewable fleet. The approach included a statistical analysis of how wind output was correlated with demand, and how much forecasting error in wind output was likely to be faced over different scheduling horizons. Benefits of geographic diversity of the wind fleet were also assessed.
- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer.
- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.
- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.
- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The Brattle team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.
- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.
- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission services for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.

- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and service mixes for pipelines that would provide more dynamically efficient signals and incentives.
- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

Financial Analysis and Commercial Litigation

- For the government of Colombia, Mr. Graves testified in arbitration about misrepresentations that occurred in the negotiation of royalties over coal mining production. Those negotiations resulted in a royalty scheme that was much more favorable to the coal company than would have been acceptable to Colombia had more realistic representations occurred. He showed that the mining companies own studies projected much higher value and more favorable operating conditions for the facility, and that alternative schedules for running the mine would have produced more value than was asserted possible by its owners.
- For the co-owners of the SONGS nuclear power plant that had become inoperable due to failed and irreparable steam generators, Mr. Graves provided written and oral testimony in arbitration over what damages had been incurred by the utilities from having to replace the nuclear plant with new generation, purchased power, and transmission upgrades, as well as accelerated decommissioning liabilities. His report evaluated the impacts of the lost plant on the entire western power market, including how it would change the needs and costs for emission allowances in the California GHG market. He estimated that damages were nearly $7 billion dollars.
- For an international energy company seeking to expand its operations in the US, Mr. Graves lead an assessment of the market performance risks facing a possible acquisition target, in order to determine what contingencies or market shifts were critical to it being an attractive target. Uncertain long run wholesale energy conditions, tightening environmental regulations, and disruptive technology development prospects were considered.
- For an international technology firm that had experienced a recent bankruptcy, Mr. Graves assisted in the design of a study of how the remaining valuable assets could be deemed assignable to disparate country-specific claims. Company operating practices for research and development risk and profit sharing were evaluated to identify an equitable approach.

- For a merchant power company with a prematurely terminated development contract, Mr. Graves co-lead a team to value the lost contract. The contract included several different kinds of revenue streams of different risks, for which Brattle developed different discount rates and debt carrying-capacity assessments. The case was settled with a very large award consistent with the Brattle valuations.
- Holding company utilities with many subsidiaries in different states face differing kinds of regulatory allowances, balancing accounts with differing lags and allowed returns for cost recovery, possibly different capital structures, as well as different (and varying) operating conditions. Given such heterogeneity, it can be difficult to determine which subsidiaries are performing well vs. poorly relative to their regulatory and operational challenges. Mr. Graves developed a set of financial reporting normalization adjustments to isolate how much of each subsidiary's profitability was due to financial, vs. managerial, vs. non-recurring operational conditions, so that meaningful performance appraisal was possible.
- Many banks, insurance firms and capital management subsidiaries of large multinational corporations have entered into long term, cross border leases of properties under sale and leaseback or lease in, lease out terms. These have been deemed to be unacceptable tax shelters by the IRS, but that is an appealable claim. Mr. Graves has assisted several companies in evaluating whether their cross border leases had legitimate business purpose and economic substance, above and beyond their tax benefits, due to likelihood of potentially facing a role as equity holder with ownership risks and rewards. He has shown that this is a case-specific matter, not per se determined by the general character of these transactions.
- For a private energy hedge fund providing risk management contracts to industrial energy users, a breach of contract from one industrial customer was disputed as supposedly involving little or no loss because the fund had not been forced to liquidate positions at a loss that corresponded precisely to the abruptly terminated contract. Mr. Graves provided analysis demonstrating how the portfolio loss was borne, but other fund management metrics used to control positions, and other unrelated hedging positions, also changed roughly concurrently in a manner that disguised the way the economic damage was realized over time. The case was settled on favorable terms for Mr. Graves' client.
- Many utilities have regulated and unregulated subsidiaries, which face different types and degrees of risk. Mr. Graves lead a study of the appropriate adjustments to corporate hurdle rates for the various lines of business of a utility with many types of operations.
- A company that incurred Windfall Tax liabilities in the U.K. regarded those taxes as creditable against U.S. income taxes, but this was disputed by the IRS. Mr. Graves lead a team that prepared reports and testimony on why the Windfall Tax had the character of a typical excess profits tax, and so should be deemed creditable in the U.S. The tax courts concurred with this opinion and allowed the claimed tax deductions in full.
- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other

concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.

- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.
- Mr. Graves has assisted leasing companies with analyses of the tax-legitimacy of complex leasing transactions. These analyses involved reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent, purpose and cost of defeasance, and compliance with prevailing guidelines for true-lease status.
- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort (POLR) obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage of the liability would have compared in costs to a proposed restructuring of the obligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.
- Several banks were accused of aiding and abetting Enron's fraudulent schemes and were sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity analyst's reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect.
- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary, overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.
- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.
- For a major electronics and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.

- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.
- The energy and telecom industries, especially in the late 1990s and early 2000s, were plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.
- Dramatic natural gas price increases in the U.S. have put several natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.
- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a "control premium" was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.
- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.
- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to

valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.

- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.
- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.
- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.
- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, e.g., based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.
- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.
- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for

comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.

- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.
- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.
- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.
- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.
- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

TESTIMONY

For Nicor Gas Company, a natural gas distribution company, Mr. Graves co-authored testimony on the cost of equity capital utilizing a broad spectrum of risl-pricing methods, and explaining how financial leverage affects it. Testimony was filed with the Illinois Commerce Commission, Docket 18-xxxx, November 9, 2018.

For the electric transmission division of Pacific Gas & Electric, Mr. Graves presented testimony and co-authored an accompanying report on the cost of capital impacts from the extreme risks arising from potential liability for damages caused by large wildfires in California. Testimony before the FERC, Docket ER19- ___ - 000, Exhibit PGE-0019, October 1, 2018.

For the Government of Colombia, written and oral testimony in regard to apparent misrepresentations of coal mine development costs and expected profitability by Glencore Corporation that adversely affected royalty payments for Colombia. Heard in the International Court of Arbitration, ICSID Case No ARB/16/6, Washington DC, June 2018.

Before the Pennsylvania Public Utility Commission, written direct testimony for Philadelphia Gas Works, Docket No. R-2017-2586783, June 2017, regarding financial benchmarking of the company vs. investor owned and public agency peers, and the need for a rate increase to maintain financial metrics and cover future costs.

Direct testimony in regard to a claim for a share of lime consumption reduction costs obtained by Plum Point as one of SMEPA's power plant operator/suppliers, on behalf of SMEPA, before the American Arbitration Association in the matter of Southwest Mississippi Electric Power Association vs. Plum Point Energy Associates, Case No. 01-15-0002-6062, September 2016.

Direct, Rebuttal and Supplementary Rebuttal reports regarding damages from loss of a nuclear generation facility, on behalf of Southern California Edison Company, Edison Material Supply LLC., San Diego Gas and Electric Company and City of Riverside before the International Chamber of Commerce in the matter of Southern California Edison v. Mitsubishi Nuclear Energy Systems, Inc. and Mitsubishi Heavy Industries, Ltd., Case No. 19784/AGF/RD, July 27, 2015 (direct), January 19, 2016 (rebuttal) and March 14, 2016 (supplemental).

Direct report re determination of an appropriate level of return needed for Standard Offer Service (SOS), on behalf of Delmarva Power & Light Company and Potomac Electric Power Company before the Maryland Public Service, Case Nos. 9226 and 9232, July 24, 2015.

Direct testimony in regard to the prudence of its gas hedging, on behalf of Hope Gas, Inc., before the West Virginia Public Service Commission, Case No. 12-1070-G-30C, June 24, 2013.

Direct testimony on behalf of Public Service Company of New Mexico before the NM Public Regulation Commission re appropriate profit incentives for energy conservation activities, Case No. 12-00317-UT, October 5, 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Utah in regard to hedging practices for natural gas supply, Docket 11-035-200, July 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Wyoming in regard to gas supply hedging and loss-sharing, Docket No. 20000-405-ER-11, June 2012.

Direct testimony on behalf of Ohio Power Company before the PUC of Ohio in regard to performance of PJM capacity markets, in Ohio Power's application for its ESP service charges, Case No. 10-2929-EL-UNC, March 30, 2012.

Expert report and oral testimony on behalf of Pepco Holdings, Inc. before the Maryland Public Service Commission in regard to inadequacies in the MD PSC's RFP for new combined cycle generation development in SWMAAC, Case No. 9214, January 31, 2012.

Direct testimony on behalf of Columbus Southern Power Company and Ohio Power Company before the Public Utilities Commission of Ohio in the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, Case No. 10-2929 -EL-UNC, August 31, 2011.

Rebuttal report on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 07-876C, No. 07-875C, No. 07-877C, August 5, 2011.

Direct Testimony on rehearing regarding the allowance of swaps in Rocky Mountain Power's fuel adjustment cost recovery mechanism, on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, July 2011.

Comments and Reply Comments on capacity procurement and transmission planning on behalf of New Jersey Electric Distribution Companies before the State of New Jersey Board of Public Utilities in the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, NJ BPU Docket No. EO11050309, June 17, 2011; July 12, 2011.

Rebuttal testimony regarding Rocky Mountain Power's hedging practices on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, Docket No. 10-035-124, June 2011.

Expert and Rebuttal reports regarding contract termination damages, on behalf of Hess Corporation before the United States District Court for the Northern District of New York, Case No. 5:10-cv-587 (NPM/GHL), April 29, 2011, May 13, 2011.

Expert and Rebuttal reports on spent fuel removal at Rancho Seco nuclear power plant, on behalf of Sacramento Municipal Utility District before the U.S. Court of Federal Claims, No. 09-587C, October 2010, July 1, 2011.

Rebuttal testimony on the Impacts of the Merger with First Energy on retail electric competition in Pennsylvania, on behalf of Allegheny Power before the Pennsylvania Public Utility Commission, Docket Nos. A-2010-2176520 and A-2010-2176732, September 13, 2010.

Expert and Rebuttal reports on the interpretation of pricing terms in a long term power purchase agreement, on behalf of Chambers Cogeneration Limited Partnership before the Superior Court of New Jersey, Docket No. L-329-08, August 23, 2010, September 21, 2010.

Expert and Rebuttal reports on spent fuel removal at Trojan nuclear facility, on behalf of Portland General Electric Company, The City of Eugene, Oregon, and PacifiCorp before the United States Court of Federal Claims No. 04-0009C, August 2010, June 29, 2011.

Rebuttal and Rejoinder testimonies on the approval of its Smart Meter Technology Procurement and Installation Plan before the Pennsylvania Public Utility Commission on behalf of West Penn Power Company d/b/a Allegheny Power, Docket No. M-2009-2123951, October 27, 2009, November 6, 2009.

Supplemental Direct testimony on the need for an energy cost adjustment mechanism in Utah to recover the costs of fuel and purchased power, on behalf of Rocky Mountain Power before the Public Service Commission of Utah, Docket No. 09-035-15, August 2009.

Expert and Rebuttal reports on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 98-126C, No. 98-154C, No. 98-474C, April 24, 2009, July 20, 2009.

Expert report in regard to opportunistic under-collateralization of affiliated trading companies, on behalf of BJ Energy, LLC, Franklin Power LLC, GLE Trading LLC, Ocean Power LLC, Pillar Fund LLC and Accord Energy, LLC before the United States District Court for the Eastern District of Pennsylvania, No. 09-CV-3649-NS, March 2009.

Rebuttal report in regard to appropriate discount rates for different phases of long-term leveraged leases, on behalf of Wells Fargo & Co. and subsidiaries, Docket No. 06-628T, January 15, 2009.

Oral and written direct testimony regarding resource procurement and portfolio design for Standard Offer Service, on behalf of PEPCo Holdings Inc. in its Response to Maryland Public Service Commission, Case No. 9117, October 1, 2008 and December 15, 2008.

Direct testimony regarding considerations affecting the market price of generation service for Standard Service Offer (SSO) customers, on behalf of Ohio Edison Company, et al., Docket 08-125, July 24, 2008.

Direct testimony in support of Delmarva's "Application for the Approval of Land-Based Wind Contracts as a Supply Source for Standard Offer Service Customers," on behalf of Delmarva Power & Light Company before the Public Service Commission of Delaware, July 24, 2008.

Oral direct testimony in regard to the Government's performance in accepting spent nuclear fuel under contractual obligations established in 1983, on behalf of plaintiff Dairyland Power Cooperative before the United States Court of Federal Claims (No. 04-106C), July 17, 2008.

Direct testimony for Delmarva Power & Light on risk characteristics of a possible managed portfolio for Standard Offer Service, as part of Delmarva's IRP filings (PSC Docket No. 07-20), March 20, 2008 and May 15, 2008.

Oral direct testimony regarding the economic substance of a cross-border lease-to-service contract for a German waste-to-energy plant on behalf of AWG Leasing Trust and KSP Investments, Inc before U. S. District Court, Northern District of Ohio, Eastern Division, Case No. 1:07CV0857, January 2008.

Expert report (October 15, 2007) and oral testimony (September 21 and 22, 2010) in Commonwealth of Pennsylvania Department of Environmental Protection, et al., v. Allegheny Energy Inc, et al. regarding flaws in the plaintiffs' assessment of emissions attributed to repairs at certain power plants, Civil Action No, 2:05ev1885.

Direct testimony regarding portfolio management alternatives for supplying Standard Offer Service, on behalf of Potomac Electric Power Company and Delmarva Power & Light Company before the Public Service Commission of Maryland, Case No. 9117, September 14, 2007.

Direct testimony in regard to preconditions for effective retail electric competition, on behalf of New West Energy Corporation before the Arizona Commerce Commission, Docket No. E-03964A-06-0168, August 31, 2007.

Direct and rebuttal testimonies regarding the application of OG&E for an order of commission granting preapproval to construct Red Rock Generating Facility and authorizing a recovery rider, on behalf of Oklahoma Gas & Electric Company (OG&E) before the Corporation Commission of the State of Oklahoma, Case No. PUD 200700012, January 17, 2007 and June 18, 2007.

Testimony in regard to whether defendant's role in accounting misrepresentations could be reliably associated with losses to shareholders, on behalf of defendant Mark Kaiser before U.S. District Court of New York SI:04Cr733 (TPG).

Rebuttal testimony on proposed benchmarks for evaluating the Illinois retail supply auctions, on behalf of Midwest Generation EME L.L.C. and Edison Mission Marketing and Trading before the Illinois Commerce Commission Docket No. 06-0800, April 6, 2007.

Direct and rebuttal testimonies on the shareholder impacts of Dynegy's Project Alpha for the sentencing of Jamie Olis, on behalf of the U.S. Department of Justice before the United States District Court, Southern District of Texas, Houston Division, Criminal No. H-03-217, September 12, 2006.

Direct and rebuttal testimony on the need for POLR rate cap relief for Metropolitan Edison and Pennsylvania Electric and the prudence of their past supply procurement for those obligations, on behalf of FirstEnergy Corp before the Pennsylvania Public Utility Commission, Docket Nos. R-00061366 and R-00061367, August 24, 2006.

Direct testimony regarding Deutsche Bank Entities' opposition to Enron Corp's amended motion for class certification, on behalf of the Deutsche Bank Entities before the United States District Court, Southern District of Texas, Houston Division, Docket No. H-01-3624, February 2006.

Expert and Rebuttal reports regarding the non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract, on behalf of Pacific Gas and Electric Company before the United States Court of Federal Claims, Docket No. 04-0074C, into which has been consolidated No. 04-0075C, November 2005.

Direct testimony regarding the appropriate load caps for a POLR auction, on behalf of Midwest Generation EME, LLC before the Illinois Commerce Commission, Docket No. 05-0159, June 8, 2005.

Affidavit regarding unmitigated market power arising from the proposed Exelon—PSEG Merger, on behalf of Dominion Energy, Inc. before the Federal Energy Regulatory Commission, Docket No. EC05-43-000, April 11, 2005.

Expert and rebuttal reports and oral testimonies before the American Arbitration Association on behalf of Liberty Electric Power, LLC, Case No. 70 198 4 00228 04, December 2004, regarding damages under termination of a long-term tolling contract.

Oral direct and rebuttal testimony before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Docket No. 98-154 C, July 2004 (direct) and August 2004 (rebuttal), regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Direct, supplemental and rebuttal testimony before the Public Service Commission of Wisconsin, on behalf of Wisconsin Public Service Corporation and Wisconsin Power and Light Company, Docket No. 05-EI-136, February 27, 2004 (direct), May 4, 2004 (supplemental) and May 28, 2004 (rebuttal) in regard to the benefits of the proposed sale of the Kewaunee nuclear power plant.

Testimony before the Public Utility Commission of Texas on behalf of CenterPoint Energy Houston Electric LLC, Reliant Energy Retail Services LLC, and Texas Genco LP, Docket No. 29526, March 2004 (direct) and June 2004 (rebuttal), in regard to the effect of Genco separation agreements and financial practices on stranded costs and on the value of control premiums implicit in Texas Genco Stock price.

Rebuttal and additional testimony before the Illinois Commerce Commission, on behalf of Peoples Gas Light and Coke Company, Docket No. 01-0707, November 2003 (rebuttal) and January 2005 (additional rebuttal), in regard to prudence of gas contracting and hedging practices.

Rebuttal testimony before the State Office of Administrative Hearings on behalf of Texas Genco and CenterPoint Energy, Docket No. 473-02-3473, October 23, 2003, regarding proposed exclusion of part of CenterPoint's purchased power costs on grounds of including "imputed capacity" payments in price.

Rebuttal testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Ameren Energy Generating Company and Union Electric Company, Docket No. EC03-53-000, October 6, 2003, in regard to evaluation of transmission limitations and generator responsiveness in generation procurement.

Rebuttal testimony before the New Jersey Board of Public Utilities on behalf of Jersey Central Power & Light Company, Docket No. ER02080507, March 5, 2003, regarding the prudence of JCP&L's power purchasing strategy to cover its provider-of-last-resort obligation.

Oral testimony (February 17, 2003) and expert report (April 1, 2002) before the United States District Court, Southern District of Ohio, Eastern Division on behalf of Ohio Edison Company and Pennsylvania Power Company, Civil Action No. C2-99-1181, regarding coal plant maintenance projects alleged to trigger New Source Review.

Expert Report before the United States District Court on behalf of Duke Energy Corporation, Docket No. 1:00CV1262, September 16, 2002, regarding forecasting changes in air pollutant emissions following coal plant maintenance projects.

Direct testimony before the Public Utility Commission of Texas on behalf of Reliant Energy, Inc., Docket No. 26195, July 2002, regarding the appropriateness of Reliant HL&P's gas contracting, purchasing and risk management practices, and standards for assessing HL&P's gas purchases.

Direct and rebuttal testimonies before the Public Utilities Commission of the State of California on behalf of Southern California Edison, Application No. R. 01-10-024, May 1, 2002, and June 5, 2002, regarding Edison's proposed power procurement and risk management strategy, and the regulatory guidelines for reviewing its procurement purchases.

Rebuttal testimony before the Texas Public Utility Commission on behalf of Reliant Resources, Inc., Docket No. 24190, October 10, 2001, regarding the good-cause exception to the substantive rules that Reliant Resources, Inc. and the staff of the Public Utility Commission sought in their Provider of Last Resort settlement agreement.

Direct testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Northeast Utilities Service Company, Docket No. ER01-2584-000, July 13, 2001, in regard to competitive impacts of a proposed merchant transmission line from Connecticut to Long Island.

Direct testimony before the Vermont Public Service Board on behalf of Vermont Gas Systems, Inc., Docket No. 6495, April 13, 2001, regarding Vermont Gas System's proposed risk management program and deferred cost recovery account for gas purchases.

Affidavit on behalf of Public Service Company of New Mexico, before the Federal Energy Regulatory Commission (FERC), Docket No. ER96-1551-000, March 26, 2001, to provide an updated application for market based rates.

Affidavit on behalf of the New York State Electric and Gas Corporation, April 19, 2000, before the New York State Public Service Commission, In the Matter of Customer Billing Arrangements, Case 99-M-0631.

Supplemental Direct and Reply Testimonies of Frank C. Graves and A. Lawrence Kolbe (jointly) on behalf of Southern California Edison Company, Docket Nos. ER97-2355-00, ER98-1261-000, ER98-1685-000, November 1, 1999, regarding risks and cost of capital for transmission services.

Expert report before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, Plaintiff v. United States of America, No. 98-154 C, June 30, 1999, regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Maine Yankee Atomic Power Company, Maine Yankee Atomic Power Company, Plaintiff v. United States of America, No. 98-474 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Yankee Atomic Electric Company, Yankee Atomic Electric Company, Plaintiff v. United States of America, No. 98-126 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Prepared direct testimony before the Federal Energy Regulatory Commission on behalf of National Rural Utilities Cooperative Finance Corporation, Inc., Cities of Anaheim and Riverside, California v. Deseret Generation & Transmission Cooperative, Docket No. EL97-57-001, March 1999, regarding cost of service for rural cooperatives versus investor-owned utilities, and coal plant valuation.

Expert report and oral examination before the Independent Assessment Team for industry restructuring appointed by the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation, January 1999, regarding the cost of capital for generation under long-term, indexed power purchase agreements.

Oral testimony before the Commonwealth of Massachusetts Appellate Tax Board on behalf of Indeck Energy Services of Turners Falls, Inc., Turners Falls Limited Partnership, Appellant vs. Town of Montague, Board of Assessors, Appellee, Docket Nos. 225191-225192, 233732-233733, 240482-240483, April 1998, regarding market conditions and revenues assessment for property tax basis valuation.

Direct and joint supplemental testimony before the Pennsylvania Public Utility Commission on behalf of Pennsylvania Electric Company and Metropolitan Edison Company, No. R-00974009, et al., December 1997, regarding market clearing prices, inflation, fuel costs, and discount rates.

Direct Testimony before the Pennsylvania Public Utilities Commission on behalf of UGI Utilities, Inc., Docket No. R-00973975, August 1997, regarding forecasted wholesale market energy and capacity prices.

Testimony before the Public Utilities Commission of the State of California on behalf of the Southern California Edison Company, No. 96-10-038, August 1997, regarding anticompetitive implications of the proposed Pacific Enterprises/ENOVA mergers.

Direct and supplemental testimony before the Kentucky Public Service Commission on behalf of Big Rivers Electric Corporation, No. 97-204, June 1997, regarding wholesale generation and transmission rates under the bankruptcy plan of reorganization.

Affidavit before the Federal Energy Regulation Commission on behalf of the Southern California Edison Company in Docket No. EC97-12-000, March 28, 1997, filed as part of motion to intervene and protest the proposed merger of Enova Corporation and Pacific Enterprises.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
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EXHIBIT SCE-24

EXHIBIT TO THE TESTIMONY OF MR. FRANK GRAVES

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

California Megafires

APPROACHES FOR RISK COMPENSATION AND FINANCIAL RESILIENCY AGAINST EXTREME EVENTS

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April 9, 2019

THE Brattle GROUP

Notice

This report was prepared for Southern California Edison ("SCE"). SCE has not prepared or independently confirmed the analysis in this report. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group generally or its client.

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Executive Summary

The increasing severity of wildfires in California is focusing attention on how to prepare for and allocate unexpected and extreme financial burdens on utility customers and shareholders. In 2017, massive wildfires throughout the state resulted in record levels of injury, property destruction and economic damage. The 2018 wildfire season was even more catastrophic, resulting in many fatalities and destruction from the largest and costliest fires in the state's recorded history.

This paper evaluates the magnitude of risks from potential liability for electric utility investors from the damages these megafires can cause. This type of exposure is referred to as an asymmetric risk, in that it is one-sided, involving only downside potential for uncompensated losses. This possibility significantly erodes investors' expected returns and could impede a California investor-owned utility from pursuing its normal operations effectively. We explain why such risks are not fully measured or quantified in ordinary estimates of the cost of capital but need special compensation, and how the cost of equity could be adjusted in order to restore the opportunity to earn a fair return on its utility investments. Specifically, we show a range of potential supplements to Southern California Edison's ("SCE") allowed return on equity ("ROE") to cover various levels of potential fire damage costs. At the extreme end, a supplement of about 600 basis points, equivalent to slightly more than $1.0 billion per year of net income, would be commensurate with the apparent largest size of the fire problem as it has been manifest over the past few years.[1]

The paper is organized as follows:

First, after an overview (Section I), we describe the history and growing scale of wildfires in California and the damages and costs associated with these fires (Sections II.A and II.B).

Second, we describe California's no-fault inverse condemnation doctrine and how that doctrine is in conflict with the California Public Utilities Commission's ("CPUC") prudency standard (Section II.C). We also address the partial protections being implemented under Senate Bill SB 901 and its implications for future liabilities.

Third, we explain how the trend of increasingly severe megafires, creating conflicts between no-fault inverse condemnation and the CPUC's cost-recovery standards, has had significant adverse impacts on the financial health and risks of California's investor-owned utilities, including SCE (Section II.D).

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1 More specifically, our reference case risk analysis measured a supplement of 611 and 571 basis points for the two approaches used, equivalent to approximately $1 billion of net income. However, sensitivity analysis showed a range from 450 to over 750 basis points, making 600 basis points an appropriate and cleaner indicator of the required supplementary compensation, given the uncertainties in the fire incidence and cost data.

Fourth, we explain the concept of asymmetric risks for utilities (in Section III.A, treated in further detail Appendix A) as to how they arise and why they are not adequately measured in the conventional cost of capital. We provide an illustration of how this risk can be addressed through a supplemental ROE (Section III.B). More specifically, to quantify the ROE supplement SCE would need for these risks, we first look at potential loss sizes as revealed from the history of California megafires, including information on a few hundred of them recognized in its recent Risk Assessment and Mitigation Phase ("RAMP") proceeding at the CPUC. Based on this data, SCE projects "tail event" wildfire loss exposure of about $1.4 billion, which is the average total cost of the worst 10% of predicted wildfire damages modeled in their RAMP filing, before mitigation, insurance, or other offsets. As explained later in this report, since SCE is not configured like a true insurance company (with diversified positions reducing overall risk), it would be entirely reasonable for it to seek protection against much bigger than average fires.

As a basis for quantifying the exposure, we update the RAMP fire data for additional late 2017 and 2018 events that had not occurred at the time of SCE's RAMP analysis, and which may be associated with utility equipment. We apply the methods of risk analytics from SCE's RAMP filing to this augmented data and then evaluate its costs with California wildfire-specific insurance pricing data using two approaches: (i) prices prevailing in the catastrophe bond market, and (ii) public information on recent utility insurance policy costs. These approaches to quantification show that replicating the costs of 3rd party insurance applied to our reference case for wildfire probabilities, less the tax shield SCE might generate as a self-insurer,[2] would have an annual cost of about $1 billion. If recovered in the form of incremental ROE, this annual would equate to approximately 600 basis points applied to SCE's $18 billion of equity rate base. Importantly, this incremental ROE can only be viewed to be compensatory in a statistical sense, and would not in all instances protect against damages from megafires in California. Alternative simulations of wildfire occurrence would require different compensation.

Finally, we explain that even though it is essential that SCE be compensated against what are currently open-ended fire liabilities, there are significant limitations of using a supplemental ROE allowance to address this risk, and we suggest that other more sustainable solutions may be available. In brief, an ROE supplement should be a temporary solution to making sure the industry and its customers have some assurance of viability and reasonable (partially limited) costs should a major fire occur. However, it cannot be construed as a sustainable, nor sufficient solution for the long run. It is likely that much broader sharing of both the prior and realized costs of coping with fires is necessary for the long run.

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2 We assume that wildfire claims would be deductible against SCE's taxable income.

I. Overview

California's existing precedent for utility liability and cost recovery in connection with wildfires is complex. California applies the concept of "inverse condemnation," which presumes a no-fault framework whereby the costs of property damages ensuing from fires substantially caused by utility equipment are shared by all customers through utility rates. However, the CPUC also has its own process of reasonableness review which can annul the no-fault framework. This CPUC process applies prudence tests for cost causality that can result in disallowing some or all costs from recovery in rates, creating material potential financial exposure for the affected utilities, without clear guidelines or standards for when and to what extent such liability can occur.

Third-party estimates of SCE's potential liabilities for the 2017 megafires are on the order of $4 billion or more,[3] and investigations into the cause and liabilities of the 2018 wildfires are still in process. SCE has recorded a $4.7 billion charge (before recoveries and taxes) for 2017 and 2018 wildfire-fire related claims.[4] Anticipating such large potential claims, and recognizing the recent result of an almost 10-year long proceeding ending with the CPUC's decision adverse to San Diego Gas & Electric Company ("SDG&E") on its 2007 fire liabilities, SCE's stock price dropped significantly after the 2017 and 2018 southern California wildfires (especially the Thomas and Woolsey fires). Recent legislation enacted in California—Senate Bill 901, focused primarily on the 2017 wildfires but with general ramifications for all California utilities—attempts to create some limits and clarity around the wildfire-related cost and risk issues for electric utilities. However, the bill does not attempt to change inverse condemnation law nor does it mandate a long term solution. Thus, it remains to be seen how or whether regulators will improve policies for this risk in the long run. Meanwhile, the state's currently unresolved approach leaves a very large and poorly defined risk on utility shareholders.

Utilities undoubtedly have an important role to play in fire-risk mitigation and recovery. But this role needs to be carefully cast in terms of clearly defined *a priori* responsibilities and agreed budgets for level of effort relative to other necessary and beneficial activities of electricity service. The utilities' role must also be defined by compliance incentives and penalties that target a socially desirable and cost-effective level of responsibilities for prevention and insurance. SCE (and the other California utilities) has initiated a Risk Assessment and Mitigation Phase ("RAMP") based on statistical and economic principles which it presented in its November 2018 filing with the CPUC.

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[3] "Fitch Maintains Southern California Edison & Edison International on Rating Watch Negative," Fitch Ratings, August 23, 2018, accessed February 2019, https://www.fitchratings.com/site/pr/10042429. *See also* Figure 3 for details on gross utility loss for SCE. SCE 2017 gross liabilities are a result of the December southern California wildfires.

[4] Southern California Edison Company, Form 10-K for the Fiscal Year Ended December 31, 2018, pages 5 and 104–107, accessed February 2019, https://www.edison.com/home/investors/sec-filings-financials/sec-filings.html.

This is a foundational step. However, even with very sophisticated and perfectly applied risk planning and management (executing all the agreed measures), wildfires are simply too difficult to fully prevent, predict, or control – hence too difficult to accurately or always adequately compensate their risk.

The regulatory and financial environment in which utilities must now prepare for the potentially extreme costs of megafires is neither sustainable nor efficient. One improvement to the status quo would be to provide utilities with a supplemental ROE allowance for the risks from potentially disallowed recovery costs that may arise even when complying fully with planned and agreed efforts to mitigate—a risk which now falls on shareholders without compensation. This need arises because fire damage risks are mostly wholly different from normal utility business risks and are largely not reflected in the cost of capital nor fully covered in any other kind of anticipatory funding mechanism remotely commensurate with the scale of possible megafire disasters. Specifically, fire damage risks are an acute example of "asymmetric risk"—that is, risks that arise when the utility facing potential obligations to pay for extreme losses in the event of adverse circumstances, but it has no offsetting opportunity for gains in times when such risks do not materialize. This is a "tails I lose, heads I break even" situation. If such risks are neither compensated nor offset with other mitigation, they are a *per se* impairment of the utility's ability to recover its costs and to expect to earn a fair return on its invested capital.

We show herein, based on our evaluation of realized costs of several recent megafires and on evidence from the costs of insurance and catastrophe bonds, that the annualized cost to SCE from the currently apparent full range of this problem is on the order of $1 billion or more. This amount of net income is equivalent to about 600 basis points as an increment to SCE's cost of equity applied to its total equity rate base.

We caution that there are multiple challenges and limitations to applying this ROE approach, not least that there are very considerable estimation difficulties of the appropriate amount. Given the recent growth in severity of fires, it is possible that even a large supplement only partly addresses the problem. At the same time, any supplemental ROE allowance may create the impression in the eyes of the public and regulators that the utilities have been fully compensated for this risk, and that customers are consequently fully insulated from pass-through of damage costs from all potential megafire catastrophes. This is not correct. Even with such compensation, SCE is not (and no utility is) configured like a true insurance company. It does not have a diversified portfolio of uncorrelated risks nor capital invested for insurance purposes from many policy holders. Thus, it cannot face such risks in the same way that we normally distribute them in risk markets and social policies; this is a stop-gap solution. Ultimately, megafire risk needs a comprehensive and sustainable solution that is broader than the precedent cost recovery framework supports. The dramatic scale of this supplemental ROE requirement (more than half of the normal cost of equity capital), calls for consideration of alternative approaches and mechanisms for financial preparedness and planning for extreme events, drawing from lessons learned and insights from California's past megafires, the insurance industry, and elsewhere in the U.S. electricity industry. However, specific new solutions are beyond the scope of this paper.

We use the term "financial resiliency" to refer to the state's ability to recover quickly and sustainably from extreme events costing potentially billions of dollars. The goal of financial resiliency is to support the financial health of the state's utility customers, taxpayers, *and* the regulated utilities that are responsible for maintaining and investing in critical public energy infrastructure.

> We define **"financial resiliency"** as ability to quickly and sustainably recover from extreme events costing on the order of billions of dollars.

It is important to emphasize that the risk of extreme resiliency-threatening events cannot be eliminated, nor accurately anticipated economically or financially. In fact, there is good reason to believe that risks of megafires are *increasing*, due to both extreme weather-driven events and a growing population with more and more properties at the wildlife-urban interface. Even with costly mitigation measures, it will remain impossible to completely eliminate the risks of fire inherent in providing power to the public. There is simply too much uncertainty and too many uncontrollable elements (including how customers choose to settle in the wildland-urban interface ("WUI") where fire risks are high) to how and where fires could occur. Only an unlimited budget—clearly infeasible and clearly inappropriate in relation to other utility obligations—could eliminate the problem.

This paper is intended for high-level discussion about temporary means of utility risk-bearing for extreme fire events, ideally used as a bridge to other more robust approaches. Our evaluation is not a comprehensive assessment of the likelihood or cost of all types of extreme event risks faced by the utilities, their customers, or other parties in the state, nor how much would be cost-beneficial to spend on each of those risks in comparison to normal utility operations. As stated before, the introduction of a risk-adjusted ROE is not meant to serve as a long-term solution. The perceived likelihood or potential consequences of extreme fire risk and decisions about how to best manage that risk depend on judgments about an unknown future, and on subjective risk preferences and tolerances of the affected parties about how to prioritize those risks compared to other needs.

II. The Growing Need for Financial Resiliency against Extreme Events

Recent "megafires" striking California have an unprecedented financial scale that is not amenable to status quo procedures for legal liability assignment or regulatory cost recovery.

While the rest of the nation has faced the harsh realities of hurricanes, storms, flooding, and other natural disasters, Californians and others in the West have faced their own version of growing natural disasters: megafires. We characterize megafires based on geographic scope (*e.g.*, acreage affected), direct financial impacts to local residents (*e.g.*, property damage and firefighting effort), and other human and economic costs (*e.g.*, lives lost, injuries, business impacts). California has had several such megafires in recent history—including the 2018 fires covering hundreds of thousands of acres, resulting in at least $17 billion in recorded insured losses for one year alone.[5] Specifically, the Carr, Mendocino Complex, and Camp Fires in northern California and the Woolsey Fire in the south have been among the most destructive in the state's history.[6]

> **Megafires**
>
> Wildfires above and beyond the "normal" wildfire season, in terms of geographic scope, property damage and firefighting effort, and other human and economic losses

Compared to other types of natural disasters, megafires put California's electric utilities in a particularly precarious financial position. Under "inverse condemnation" principles, public utilities are subject to "no fault" cost-responsibility based on the theory that costs will be fully socialized throughout the community. The CPUC, on the other hand, applies a prudency standard to the actions of the utilities, which considers fault and prudence in evaluating whether the utility acted reasonably. Under this standard, the CPUC may prevent utilities from recovering some or all liability costs from their customers. Thus, a utility may be held liable in court under inverse condemnation because its facilities were involved in a fire regardless of fault and even if the utility was fully compliant with all applicable rules and regulations. This simply facilitates applying the revenue collection mechanisms of the utility to cover the harm, without implying any guilt or culpability. In contrast, the CPUC could preclude the utility from recovering these court-assigned liability costs from customers, if the CPUC were to find that the utility was not prudent, even if

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5 Aon Benfield, "Weather, Climate, & Catastrophe Insight: 2018 Annual Report," January 22, 2019, page 22, accessed February 2019, http://thoughtleadership.aonbenfield.com/Documents/20190122-ab-if-annual-weather-climate-report-2018.pdf.

6 *Ibid. See also* California Department of Forestry and Fire Protection, "Top 20 Most Destructive California Wildfires," last modified March 14, 2019, accessed March 2019, http://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Destruction.pdf.

the source of the alleged imprudent conduct may not directly be the cause of the fire. The difference between these two standards creates uncertainty and potentially extreme asymmetric risk for utility investors and managers. This issue is addressed in more detail below in Section II.C.

A. Growing Scale of Natural Disasters

Natural disasters, including wildfires, are resulting in increasing catastrophic physical and financial damage, as they grow in scale and severity in the U.S. and around the world.

There is much evidence that the severity of weather and climate-related natural disasters is growing on both a national and global scale.[7] The U.S. Global Change Research Program predicts increased incidence rates and intensity of extreme temperatures, heavy precipitation events, extreme storms, heat waves, and large forest fires in the west and Alaska.[8] Both the U.S. Department of Energy and the Department of Homeland Security have acknowledged additional risks and vulnerabilities to the power sector and to the economy in general as a result of these changing trends.[9,10]

The reinsurance industry, which insures private insurance companies against very large claims, catalogues trends in natural disasters and other extreme events over a broad geography and over many years. Reinsurance industry reports have documented an increase in both (a) the number

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7 *See*, for example, Intergovernmental Panel on Climate Change, "Climate Change 2014: Synthesis Report," Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, 2014, accessed February 2019, https://www.ipcc.ch/report/ar5/syr/, and "Series: Turn Down the Heat," The World Bank Group, accessed February 2019, http://www.worldbank.org/en/topic/climatechange/publication/turn-down-the-heat.

8 U.S. Global Change Research Program, "Climate Science Special Report: Fourth National Climate Assessment, Volume I," 2017, pages 21–22, accessed February 2019, https://science2017.globalchange.gov/downloads/CSSR2017_FullReport.pdf.

9 U.S. Department of Energy, "U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather," July 2013, accessed February 2019, https://www.energy.gov/sites/prod/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf.

10 U.S. Department of Homeland Security, "DHS Climate Action Plan," September 2013, accessed February 2019, https://www.dhs.gov/sites/default/files/publications/DHS%20Climate%20Action%20Plan.pdf.

and cost of loss events and (b) the volatility of losses.[11,12,13] Global economic losses from natural disasters increased 4% and 5.9% annually above the average rate of inflation from 1980–1999 and 2000–2017, respectively, with 2017 recording the highest losses from weather-related events.[14] Figure 1 shows the increase in the number of loss events in the U.S. that cost at least $1 billion, primarily due to meteorological events, such as hurricanes, and hydrological events, such as flooding.[15] Climatological events, including wildfires, are also increasing in number. In general, the scale and volatility of catastrophic event costs are growing.

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11 Munich Re, "Natural Catastrophes 2017: Analyses, Assessments, Positions," March 2018, pages 23, 42, 46, and 53, accessed February 2019, https://www.munichre.com/site/touch-publications/get/documents_E711248208/mr/assetpool.shared/Documents/5_Touch/_Publications/TOPICS_GEO_2017-en.pdf.

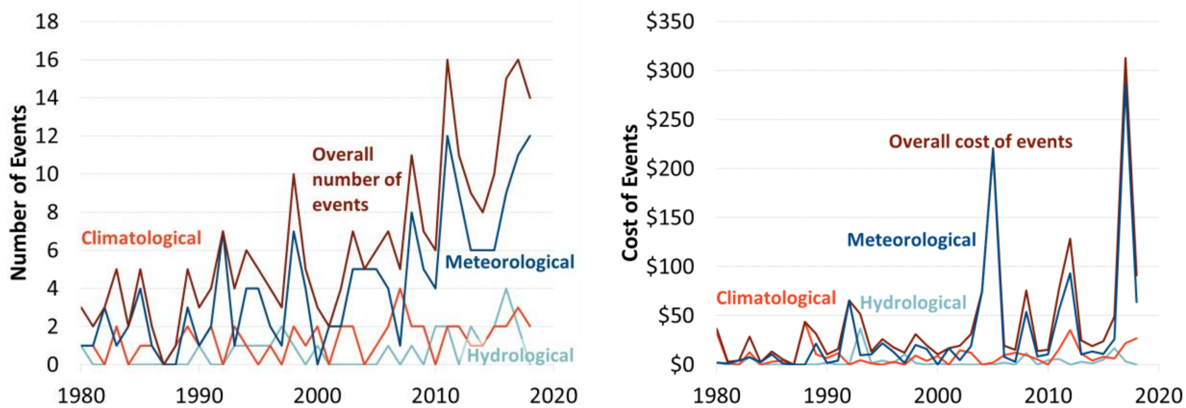
12 JLT Re, "Reinsurance Market Prospective 2019: Unchartered Territory," January 2019, page 24, accessed February 2019, https://www.jltre.com/our-insights/publications/reinsurance-market-prospective-2019/download-uncharted-territory.

13 Aon Benfield, "Weather, Climate, & Catastrophe Insight: 2018 Annual Report," January 22, 2019, pages 22, 39, and 56, accessed February 2019, http://thoughtleadership.aonbenfield.com/Documents/20190122-ab-if-annual-weather-climate-report-2018.pdf.

14 Aon Benfield, "Weather, Climate, & Catastrophe Insight: 2017 Annual Report," January 24, 2018, pages 1 and 3, accessed February 2019, http://thoughtleadership.aonbenfield.com/Documents/20180124-ab-if-annual-report-weather-climate-2017.pdf.

15 Meteorological events include tropical cyclone, extratropical storm, convective storm, and local storm. Hydrological events include floods and mass movement (such as landslides, avalanches, rock falls). Climatological events include extreme temperatures, droughts, and wildfires.

Figure 1: Billion-Dollar Weather and Climate Disasters in the U.S.
1980–2018



Sources and Notes: "Billion-Dollar Weather and Climate Disasters," NOAA National Centers for Environmental Information (NCEI), accessed February 2019, https://www.ncdc.noaa.gov/billions/time-series.

The increase in losses may be due to a combination of heightened climate risk and increased concentration of property value in at-risk areas. Both factors are also at play in California with regard to wildfires.

B. Megafires in California: Scale of Damage and Costs

California megafires cause billions of dollars of damage and potential liabilities for the state's utilities, rivaling other extreme natural disasters across the country.

Wildfires in California are commonplace, enough so that there is a substantial "normal" or "expected" amount of damages from wildfires every year. The California Department of Forestry and Fire Protection ("CAL FIRE") responds to over 5,600 wildfires annually.[16,17] However, there are occasional but much larger wildfires in the western U.S.—burning longer and burning more land and properties. An analysis performed by Climate Central using U.S. Forest Service Records from 1970 to 2015 found that the average annual number of fires larger than 1,000 acres in the 2010s was more than 3 times that in 1970s. The study also found that the average area burned was more than six times as many acres, and that the fire season was 105 days longer across the same periods.[18] A recent report published during California's Fourth Climate Change Assessment points out that by end of the century, "if greenhouse gas emissions continue to rise … the frequency of

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16 California Department of Forestry & Fire Protection, "CAL FIRE at a Glance," September 2018, accessed March 2019, http://www.calfire.ca.gov/communications/downloads/fact_sheets/Glance.pdf.

17 California Department of Forestry & Fire Protection, "2012 Strategic Plan," June 2012, page 1, accessed February 2019, http://calfire.ca.gov/about/downloads/Strategic_Plan/StrategicPlan_SinglePages.pdf.

18 Alyson Kenward, Todd Sanford, and James Bronzan, "Western Wildfires: A Fiery Future," *Climate Central*, June 2016, page 4, accessed February 2019, http://assets.climatecentral.org/pdfs/westernwildfires2016vfinal.pdf.

extreme wildfires burning over approximately 25,000 acres would increase by nearly 50%, and that average area burned statewide would increase by 77% by the end of the century. In the areas that have the highest fire risk, wildfire insurance is estimated to see costs rise by 18% by 2055 and the fraction of property insured would decrease."[19] In California, bark beetles and drought have contributed to record numbers of dead trees that fuel and amplify megafires.[20] Firefighting and property damage costs in California also tend to be particularly high compared to the rest of the West, due to factors such as relatively high population and density of human structures.[21,22] The state also has many residents living in relatively high wildfire risk areas. A wildfire risk analysis by Verisk Analytics found that 15% of households in California were at high or extreme risk from wildfires, with Los Angeles, San Diego, San Bernardino, Ventura, and Alameda counties having the largest number of housing units falling into this category.[23]

The graphic in Figure 2 shows the cost of California megafires in the context of other wildfires in the West, and compared to other U.S. natural disasters. As the figure shows, the extent of financial damage from California megafires tends to be much larger than other wildfires in the country, such as the 2011 Las Conchas fire in New Mexico, the 2011 Bastrop County Complex fire in Texas, or the 2012 Waldo Canyon fire in Colorado. Megafire costs can be on the order of billions of dollars, and they can reach hurricane-like magnitudes.

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19 California's Fourth Climate Change Assessment, "Statewide Summary Report," January 16, 2019, page 9, accessed February 2019, http://www.climateassessment.ca.gov/state/docs/20190116-StatewideSummary.pdf.

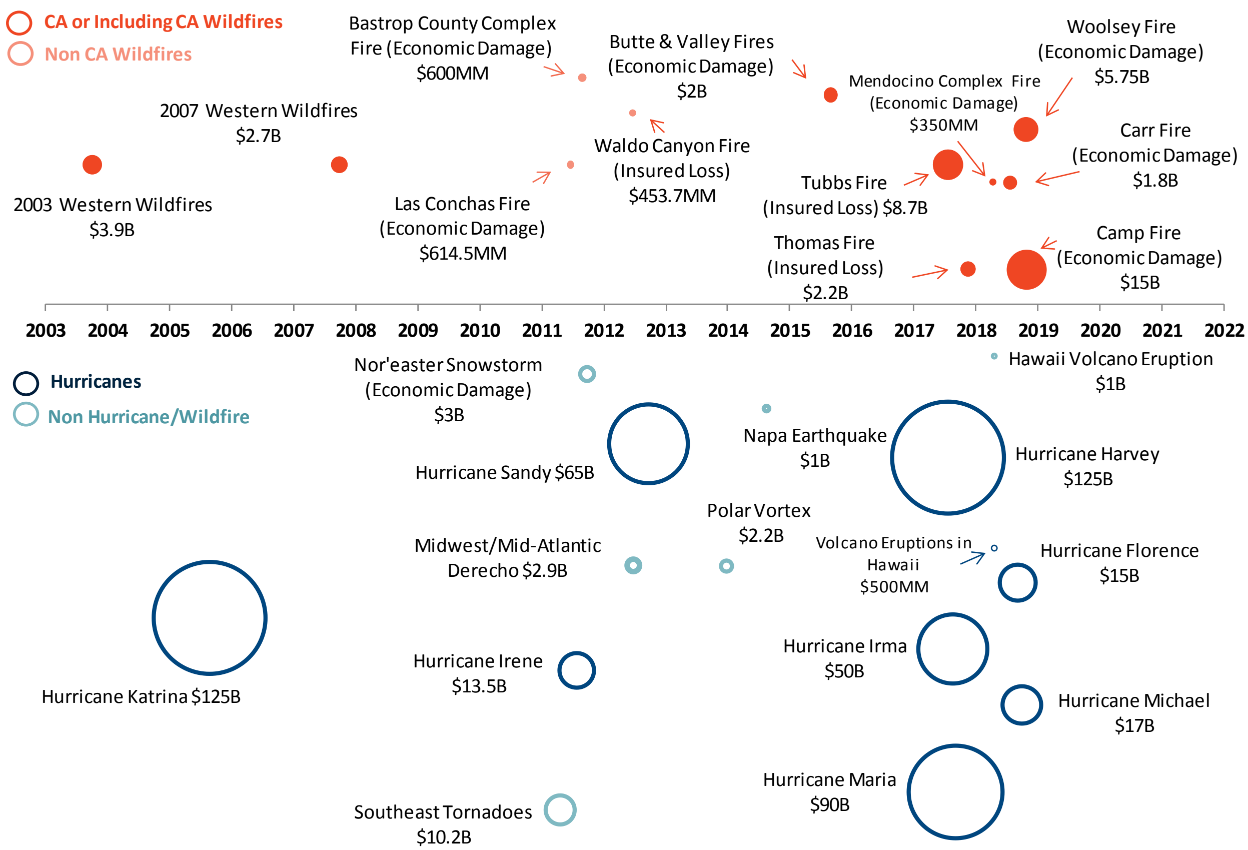
20 "Record 129 Million Dead Trees in California," California Department of Forestry and Fire Protection news release, December 11, 2017, accessed February 2019, http://calfire.ca.gov/communications/downloads/newsreleases/2017/CAL%20FIREandU.S%20ForestAnnouce129MillionDeadTrees.pdf.

21 Laignee Barron and Mahita Gajanan, "California's Wildfires Have Become Bigger, Deadlier, and More Costly. Here's Why," *Time*, October 17, 2017, accessed February 2019, http://time.com/4985252/california-wildfires-fires-climate-change/.

22 Gregory Scruggs, "Rampant land development will worsen U.S. wildfires – experts," *Reuters*, October 19, 2017, accessed February 2019, https://www.reuters.com/article/us-usa-fires-development/rampant-land-development-will-worsen-u-s-wildfires-experts-idUSKBN1CO2LR.

23 "2018 FireLine State Risk Report – California," Verisk Analytics, accessed February 2019, https://www.verisk.com/insurance/campaigns/location-fireline-state-risk-report/.

Figure 2: California Megafires in the Context of Other U.S. Natural Disasters
2003–2018



Sources and Notes: Brattle research on public data sources; see Appendix B for complete citations. Dollars represent nominal total direct financial losses, unless noted otherwise. 2018 cost estimates are incomplete and still being assessed.

Figure 3 below, provides more detail on the extent of actual and potential gross utility losses from California's megafires in 2003, 2007, 2015, 2017, and 2018. Gross losses—before any cost recovery and also regardless of insurance coverage—range widely, from $71 million due to the 2003 southern California wildfires to potentially $30 billion or more due to the 2017 and 2018 northern California wildfires.[24,25] These include the cost of recovery efforts, infrastructure damage, and potential liabilities transferred to the utilities through litigation.

24 California Public Utilities Commission, *Opinion on the Reasonableness of San Diego Gas and Electric Company's Response to the 2003 Wildfires*, Application No. 04-06-035 (Filed June 28, 2004), Decision 05-08-037, August 25, 2005, page 3.

25 Pacific Gas and Electric Company, Form 8-K, January 13, 2019, page 4, accessed February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx. Note that the $30 billion gross loss estimate is pertaining to Northern California fires in PG&E's service territory and thus does not include the Woolsey fire, which took place in Southern California.

Figure 3: Summary of California Megafires
2003–2018

Year	Name	Utility Area	Gross Utility Loss	Acreage
2018	Woolsey	SCE	TBD	96,949
	Camp Fire	PG&E	$10.5B+ est.	153,336
2017	October Northern CA Wildfires	PG&E	$10B - $17.3B est.	179,336 *(Tubbs, Nuns, Atlas, and Redwood Valley fires only)*
	December Southern CA Wildfires	SCE	$4B est.	281,893 *(Thomas Fire only)*
2015	Valley	PG&E	N/A**	76,067
	Butte	PG&E	$1.1B+ est.	70,868
2007	Southern CA Wildfires	SDG&E	$2.4B	516,465
2003	Southern CA Wildfires	SDG&E	$71MM	750,043 *(Led by Cedar fire)*

Sources and Notes: Brattle research on public data sources; see Appendix B for complete citations.

The Valley fire was not caused by PG&E equipment, but by a faulty residential electrical connection. *See* CAL FIRE Investigators Determine Cause of Destructive Valley Fire," California Department of Forestry and Fire Protection news release, August 10, 2016, accessed February 2019, http://www.fire.ca.gov/communications/downloads/newsreleases/2016/ValleyFireCause.pdf.

PG&E was not found liable for any punitive damages for the Butte Fire. *See* Iulia Gheorghiu, "California court clears PG&E of liability in 2015 fire," *Utility Dive*, July 9, 2018, accessed February 2019, https://www.utilitydive.com/news/california-court-clears-pge-of-liability-in-2015-fire/527300/.

SDG&E recorded total gross costs of $71 million due to its 2003 megafires.[26] The utility recovered about $8 million under FERC-regulated transmission service rates, and $22 million under CPUC-regulated gas and electric service rates already in place.[27] The remaining net cost of $41 million was recovered from SDG&E customers under a Catastrophic Event Memorandum Account ("CEMA") with CPUC approval.[28]

Several years later, SDG&E incurred $2.4 billion in gross costs and legal fees associated with the 2007 southern California wildfires.[29] A large share was recovered through liability insurance ($1.1

26 California Public Utilities Commission, *Opinion on the Reasonableness of San Diego Gas and Electric Company's Response to the 2003 Wildfires*, Application No. 04-06-035 (Filed June 28, 2004), Decision 05-08-037, August 25, 2005, page 3.

27 *Id.*, page 4.

28 The account was used for, "[r]ecording and recovering the costs incurred by SDG&E to restore utility service to customers, repair, replace or restore damaged facilities." *Id.*, page 36.

29 California Public Utilities Commission, *Decision Denying Application*, Application No. 15-09-010 (Filed September 25, 2015), Decision 17-11-033, November 30, 2017, page 3.

billion in coverage) and $0.8 billion in settlements with Cox Communications and three contractors. Some was recovered through FERC-regulated rates, and SDG&E proposed to voluntarily contribute $42 million.[30] A net cost of $379 million was recorded in SDG&E's Wildfire Expense Memorandum Account ("WEMA").[31] According to the CPUC, utility equipment was identified as the cause of three of more than a dozen fires.[32] At the end of 2017, the CPUC denied SDG&E's request to recover the $379 million from customers, and so these costs in addition to the $42 million voluntary loss retention were ultimately borne by shareholders under a legal and regulatory framework we discuss in the next sections. This amount represented 6.7% of SDG&E's electric book value of equity that was in place at the beginning of 2017.[33]

Utility shares of total costs from the 2015, 2017, and 2018 megafires are yet to be determined. The order of magnitude of these costs will likely depend on whether utility equipment was involved. As of the end of 2018, PG&E estimated a potential gross loss to the utility of at least $1.1 billion for the Butte Fire in northern California in 2015.[34] At the time they occurred, the late 2017 megafires in both northern and southern California were reportedly the most destructive in recent history.[35,36] Before it was determined that PG&E equipment was not the cause of the 2017 Tubbs fire,[37] an August 2018 Fitch Ratings assessment had estimated that PG&E could be liable for costs

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30 *Id.,* page 3.

31 *Id.*, pages 2–3.

32 *Id.,* page 2.

33 San Diego Gas & Electric Company, Form 10-K for the Fiscal Year Ended December 31, 2017, page F-17, accessed May 2018, http://investor.sempra.com/static-files/c53628aa-4b86-47d7-b91a-14e4e8bbc2bd.

34 "The Utility currently believes that it is probable that it will incur a loss of $1.1 billion in connection with the 2015 Butte fire." Pacific Gas and Electric Company, Form 10-K for the Fiscal Year Ended December 31, 2018, page 34, accessed February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx.

35 Munich Re, "Natural Catastrophes 2017: Analyses, Assessments, Positions," March 2018, page 45, accessed April 2018, https://www.munichre.com/site/touch-publications/get/documents_E380900654/mr/assetpool.shared/Documents/5_Touch/_Publications/302-09092_en.pdf.

36 "California statewide wildfire insurance claims nearly $12 billion," California Department of Insurance press release, January 31, 2018, accessed April 2018, http://www.insurance.ca.gov/0400-news/0100-press-releases/2018/release013-18.cfm.

37 The Tubbs Fire was caused by a private electrical system near a residential structure. *See* "CAL FIRE Investigators Determine the Cause of the Tubbs Fire," California Department of Forestry and Fire Protection news release, January 24, 2019, accessed February 2019, http://calfire.ca.gov/communications/downloads/newsreleases/2019/TubbsCause1v.pdf.

of $15 billion or more.[38] Also, in June 2018, J.P. Morgan estimated that PG&E's liabilities from the 2017 could range from $13.5 billion to $17.3 billion.[39] Further, SCE could owe up to $4 billion for the December 2017 southern California fires.[40] In 2018, three of the California's most destructive fires occurred – the Camp, Woolsey, and Mendocino Complex fires – of which the Mendocino Complex Fire was the largest recorded fire in the state's history.[41] Although no estimates of utility responsibility have yet been made public for these recent megafires, SCE has recorded a $4.7 billion charge (before recoveries and taxes) for 2017 and 2018 wildfire-fire related claims,[42] and PG&E has recorded a $3.5 billion and a $10.5 billion charge for claims related to 2017 northern California wildfires and the Camp Fire, respectively.[43]

C. Precedents for Utility Liabilities in California

California legal precedent has assigned property damage responsibility to utilities on a no-fault basis when their equipment is involved, presuming the utilities' ability to socialize the costs among customers. However, there is a high degree of regulatory uncertainty on whether no-fault full cost recovery will be allowed or would be even feasible for some megafires.

Precedent for cost recovery in connection with wildfires in California is complex. Where a utility's equipment is shown to be a substantial cause of a fire, courts can hold that the legal doctrine of "inverse condemnation" applies. Inverse condemnation imposes strict liability on the utility for property damages regardless of any finding of negligence or mismanagement, based on the presumption that a utility has the ability and is an appropriate agency to recover such costs from customers.

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38 "Fitch Maintains Pacific Gas and Electric & PG&E Corp. on RWN," Fitch Ratings, August 23, 2018, accessed February 2019, https://www.fitchratings.com/site/pr/10042430.

39 "PG&E Corp. Company Liability Estimates Tell Us Little at This Stage," J.P. Morgan, June 21, 2018, page 2, accessed September 2018.

40 "Fitch Maintains Southern California Edison & Edison International on Rating Watch Negative," Fitch Ratings, August 23, 2018, accessed February 2019, https://www.fitchratings.com/site/pr/10042429.

41 California Department of Forestry and Fire Protection, "Top 20 Most Destructive California Wildfires," last modified March 14, 2019, accessed March 2019, http://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Destruction.pdf.

California Department of Forestry and Fire Protection, "Top 20 Largest California Wildfires," last modified March 14, 2019, accessed March 2019, https://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Acres.pdf.

42 Southern California Edison Company, Form 10-K for the Fiscal Year Ended December 31, 2018, pages 5 and 107, accessed February 2019, https://www.edison.com/home/investors/sec-filings-financials/sec-filings.html.

43 Pacific Gas and Electric Company, Form 10-K for the Fiscal Year Ended December 31, 2018, pages 144, 149–150, accessed February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx.

Unlike public utilities, investor-owned utilities like SCE traditionally must have their costs approved by the CPUC in order to recover them. However, the no-fault doctrine of inverse condemnation is in conflict with the presently more subjective (or not formally articulated) standards used by the CPUC to evaluate whether to allow investor-owned utilities to pass on wildfire damage costs. This creates a highly uncertain situation for investors and utility planners. In the context of mounting exposure to potentially huge financial costs from wildfires, this disconnection underscores an acute need to rationalize catastrophic risk allocation rules. As a result of this disconnect, SCE has challenged the applicability of inverse condemnation to investor-owned utilities.

Inverse Condemnation. The Fifth Amendment of the U.S. Constitution specifies one condition for the exercise of eminent domain: that the government must fairly compensate owners when their property is taken for public purposes. The corresponding provision under California law—Article I, §19 of the California Constitution—extends this concept to include compensation for property *damage* caused by public enterprises, allowing property owners in such circumstances to take legal action against government entities under the doctrine of "inverse condemnation." In the 1960s, courts in California started to interpret inverse condemnation as imposing strict liability on government agencies, regardless of any finding of negligence.[44] This has been based on the reasoning that damages caused by public infrastructure should be borne by the full community of users, along with the presumption that public entities have the ability to spread the costs through taxation:

> "[T]he cost of such damage can better be absorbed, and with infinitely less hardship, by the taxpayers as a whole than by the owners of the individual parcels damaged."[45]

Beginning with the *Barham decision* adverse to SCE in 1999, courts extended inverse condemnation to apply to investor-owned utilities as well as government agencies.[46] In subsequent inverse condemnation rulings relating to California utilities, the premise of regulatory cost recovery has, until recently, remained as an explicit part of the rationale. For example, in a decision adverse to SCE in 2012, the court noted, "Edison has not pointed to any evidence to support its implication that the Commission would not allow Edison adjustments to pass on damages liability during its periodic reviews."[47]

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44 *Albers v. County of Los Angeles* (1965) 62 Cal.2d 250 is frequently cited as a seminal ruling on inverse condemnation. Significantly, the plaintiff's own negligence was not necessarily a bar to a finding of strict liability. *See Blau v. City of Los Angeles* (1973) 32 Cal.App.3d 77.

45 *Albers v. County of Los Angeles* (1965) 62 Cal.2d 250.

46 *Barham v. So. Cal. Edison Co.* (1999) 74 Cal.App.4th 744.

47 *Pac. Bell v. So. Cal. Edison Co.* (2012) 208 Cal.App.4th 1400. The Pacific Bell decision was echoed in a more recent Superior Court ruling finding that PG&E is liable for inverse condemnation in connection with the Butte fire (Ruling on Submitted Matter: Inverse Condemnation Motions, Butte Fire Cases, Case No.: JCCP 4853, Superior Court of California for the County of Sacramento, June 22, 2017).

Thus, to be sustainable in practice, inverse condemnation would seem to require strict flow-through of property damages back to utility customers.[48] Such a flow-through approach may have been tractable when the damages were relatively small and/or significantly offset by insurance or public funds. Now, however, with the far greater magnitude of damages incurred by recent wildfires, inverse condemnation is coming under renewed scrutiny.

CPUC's November 2017 Ruling for SDG&E. Despite the long history of inverse condemnation, the presumption of cost recovery from utility customers under its application has not been accommodated by the CPUC. Notably, regarding the damages arising from the 2007 southern California megafires affecting SDG&E, the CPUC ruled in late 2017 that the utility's actions prior to the event were not reasonable and SDG&E was therefore liable for associated costs of $379 million recorded in its Wildfire Expense Memorandum Account.[49] The CPUC found SDG&E's actions had not properly invoked inverse condemnation, noting that "[w]e are not aware of any Superior Court determination that SDG&E was in fact strictly liable for the costs requested in its application."[50] As a result of this decision grounded in more traditional utility cost recovery standards (prudence, causality), there is now uncertainty surrounding how the pending costs of more recent (much larger) fires will be allocated.[51]

California Senate Bill 901. At the end of August 2018, California passed a bill that takes some steps towards addressing the cost allocation problem for the 2017 megafires.[52] Senate Bill 901 expands various fire prevention and mitigation efforts by several state agencies, and it clarifies the CPUC's authority and approach for reasonableness review of utility activities and costs regarding fire mitigation. The bill also creates a framework for possibly socializing wildfire-related costs in 2017 and in future years through a securitized utility financing mechanism called a recovery bond.

For 2017 specifically, the bill mandates that the CPUC take into account "the electrical corporation's financial status" by determining "the maximum amount the corporation can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service."[53] The bill thus establishes a mechanism for SCE to recover costs for 2017 wildfires that would otherwise be disallowed, at least beyond the point to where the disallowance would

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48 It is less clear as to whether this would apply to all such costs, or to just the net costs after other private or other-agency mechanisms for compensation and recovery have been applied.

49 California Public Utilities Commission, *Decision Denying Application*, Application No. 15-09-010 (Filed September 25, 2015), Decision 17-11-033, November 30, 2017, pages 11, 14, 29, and 36–37.

50 *Id.*, page 65.

51 The CPUC denied SDG&E's subsequent request for rehearing in July 2018. California Public Utilities Commission, *Order Denying Rehearing of Decision (D.) 17-11-033*, Application No. 15-09-010 (Filed September 25, 2015), Decision 18-07-025, July 12, 2018.

52 California Senate Bill No. 901 (Wildfires), *Legislative Counsel's Digest*, published September 8, 2018, https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB901.

53 *Id.,* Section 27.

threaten the utility's financial viability or its ability to provide utility service. However, the CPUC has not resolved regulatory uncertainty on even the order of magnitude of a possible disallowance amount through the application of the "maximum amount" in years subsequent to 2017 or the development of a transparent, predictable cost recovery framework.[54] Thus the utilities remain financially exposed, with consequences discussed below.

D. Recent Implications for California Investor-Owned Utilities

The prospect of an SDG&E-like outcome for decisions about fires that have not yet been reviewed in regulatory proceedings creates a large financial risk for utility investors with strong implications for California's investor-owned utilities' financial health, as already evidenced in both PG&E's and SCE's stock performance and creditor reactions.

The reactions of credit rating agencies and utility investors to the SDG&E 2007 wildfire decision discussed above highlight the serious implications of the regulatory uncertainty of the utilities' ability to recover the costs of megafires on utilities' financial stability. Leading up to the November 2017 decision, for example, Moody's Investors Service stated that, "a less credit supportive regulatory environment will likely result in worse financial metrics and weakened credit quality for California IOUs."[55] In early December 2017, Moody's commented that the outcome "may make it difficult for utilities to meet the CPUC's prudency standards in the future."[56]

These financial stresses and investor concerns accelerated over the past year. On December 20, 2017, PG&E's Board of Directors announced suspension of common stock dividend payments, beginning with the fourth quarter of 2017, and suspended dividends on preferred stock, beginning with the three-month period ending January 31, 2018.[57] This dividend suspension had an immediate function to conserve cash and increase liquidity in the face of uncertainties, but it also had detrimental effects from the perspective of rating agencies and equity investors.

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[54] *See* California Public Utilities Commission, *Order Instituting Rulemaking to Implement Public Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901 (2018)*, Rulemaking 19-01-006, Assigned Commissioner's Scoping Memo and Ruling, March 29, 2019.

[55] "California wildfires could create material contingent liabilities and credit challenges," Sector Comment, Moody's Investors Service, December 20, 2017.

[56] "San Diego Gas & Electric Company: Regulator denies San Diego Gas & Electric's recovery of 2007 wildfire costs, a credit negative for all California utilities," Issuer Comment, Moody's Investors Service, December 4, 2017.

[57] Pacific Gas and Electric Company, Form 8-K, December 20, 2017, accessed April 2018, http://investor.pgecorp.com/financials/sec-filings/default.aspx.

Moody's viewed the dividend suspensions as a credit negative "because it signals how management views the company's potential exposure to the Northern California wildfires."[58] They also noted that the dividend cuts suggest that the uncertain liabilities associated with wildfire damages "may exceed liquidity reserves as well as impact the company's ability to access the capital markets, and potentially the solvency of the utility."[59] Standard & Poor's reacted similarly and downgraded PG&E's preferred stock from BBB to BB.[60] In February and March 2018, Fitch, Moody's, and Standard & Poor's each downgraded the company.[61] Moody's noted, for example, that "the uncertainty associated with the wildfire-related damages, especially those related to the application of inverse condemnation, has increased PCG and PG&E's risk profile."[62] The credit ratings agencies have maintained a negative outlook on PG&E, warning investors of the potential for further downgrades going forward.

Equity investors have responded accordingly: PG&E Corporation's stock price dropped dramatically from approximately $70 per share in early October 2017 before the northern California fires began to about $57 per share in mid-October 2017 just after the fires started. The price fell further to about $45 per share, where it remained from the announcement of the dividend suspension on December 20, 2017 through October 2018.[63] PG&E Corporation's stock price continued to decline to about $25 per share in mid-November surrounding two PG&E reports of electric safety incidents near the Camp Fire,[64] the subsequent filing of a lawsuit against the utility

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58 "Moody's Places PG&E Corporation and Pacific Gas & Electric Company's Ratings on Review for Downgrade," Moody's Investor Service, December 21, 2017.

59 *Id.*

60 "PG&E Corp. and Subsidiary Placed on CreditWatch Negative on Suspended Dividends Due to Liability Exposure," S&P Global Ratings press release, December 22, 2017.

61 "Fitch Downgrades PG&E Corp. and Sub to 'BBB+'; Places on Rating Watch Negative," Fitch Ratings Inc. press release, February 26, 2018.

"Ratings Action: Moody's Downgrades PG&E to A3 and PG&E Corp to Baa1, Outlooks are Negative," Moody's Investors Service, March 19, 2018.

"PG&E Corp. and Subsidiary Downgraded to 'BBB+' on Contingent Liabilities; Still CreditWatch Negative," S&P Global Ratings, Research Update, February 22, 2018.

62 "Ratings Action: Moody's Downgrades PG&E to A3 and PG&E Corp to Baa1, Outlooks are Negative," Moody's Investors Service, March 19, 2018.

63 "PG&E Corporation (PCG) Historical Stock Prices," *Yahoo! Finance*, accessed February 2019, https://finance.yahoo.com/quote/PCG/history?p=PCG.

64 *Electric Safety Incident Reported-Pacific Gas & Electric Incident No: 181108-9002*, reported November 8, 2018, accessed February 2019, https://assets.documentcloud.org/documents/5032723/Electric-Safety-Incident-Reported-Pacific-Gas.pdf.

Electric Safety Incident Reported-Pacific Gas & Electric Incident No: 181116-9015, accessed February 2019, reported November 16, 2019, alleging the company's negligence caused the fire,[65] and the warning that it could face liabilities in excess of its $1.4 billion insurance coverage.[66] The price dropped again to less than $10 per share in mid-January 2019 when PG&E announced it would be filing for bankruptcy,[67] before rising to about $14 per share when a CAL FIRE investigation determined that PG&E equipment was not the cause of the 2017 Tubbs Fire.[68] PG&E is expecting its bankruptcy to last around two years, when it hopes to reemerge with approved and financed liabilities for its responsibilities for 2017 and 2018 fires.[69]

Although Edison International stock is not currently at risk for such dramatic financial stresses based on the 2017 and 2018 wildfires, a similar trend of investor concern following wildfires is noticeable. Its stock price dropped from approximately $80 per share in November 2017 to about $60 per share after the December 2017 southern California wildfires, and again from around $70 in October and early November 2018 to approximately $55 per share after the Woolsey and Hill Fires.[70]

This deterioration in investor confidence is counter-productive to the state's broader efforts to manage the costs of an extreme event because it is occurring precisely at the time when an ongoing commitment of capital from investors is most needed to improve fire mitigation as well as to improve the system for other service amenities. Loss of investor confidence hampers the company's financial flexibility and ability to raise additional equity capital. It is difficult to conceive of how the regulatory uncertainty putting the regulated utilities in this financial position is helpful for the state's ability to manage the underlying risks of megafires.

Senate Bill 901 has to date only partly assuaged investor concerns, and many of its features remain to be determined or tested in application, which may take several years to resolve. On September

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http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2018/EIR_IncidentNo181116-9015.pdf.

65 Jeff Stanfield, "PG&E Corp. shares drop amid wildfire lawsuit, debt drawdown concerns," *S&P Global Market Intelligence*, November 14, 2018.

66 Pacific Gas and Electric Company, Form 8-K, November 9, 2018, accessed February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx.

67 Pacific Gas and Electric Company, Form 8-K, January 13, 2019, accessed February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx.

68 "CAL FIRE Investigators Determine the Cause of the Tubbs Fire," California Department of Forestry and Fire Protection news release, January 24, 2019, accessed February 2019, http://calfire.ca.gov/communications/downloads/newsreleases/2019/TubbsCause1v.pdf.

69 Jim Efstathiou Jr and Molly Smith, "PG&E Lines Up $5.5 billion to Fund a 2-Year Bankruptcy Process, *Bloomberg*, January 22, 2019, accessed February 2019, https://www.bloomberg.com/news/articles/2019-01-22/pg-e-lines-up-5-5-billion-to-fund-a-2-year-bankruptcy-process.

70 "Edison International (EIX) Historical Stock Prices," *Yahoo! Finance*, accessed February 2019, https://finance.yahoo.com/quote/EIX/history?p=EIX.

6, 2018, after the Legislature passed the bill, Moody's responded by further downgrading PG&E's senior unsecured ratings from A3 to Baa1, and the parent company PG&E Corporation from Baa1 to Baa2.[71] On that same day, Moody's also downgraded SCE's senior unsecured rating from A2 to A3, and its parent company Edison International from A3 to Baa1.[72] Moody's explained that "SB901 failed to address the most important risk factor, inverse condemnation, and the benefits it provides are dependent on implementation by state regulators."[73] Fitch followed suit with a downgrade to BBB for PG&E and to BBB+ for SCE on September 13, 2018, stating that, "S.B. 901 grants wide latitude to the [CPUC] to authorize recovery of third party liabilities associated with catastrophic wildfires."[74,75] Furthermore, the bill does not address fires in 2018, nor does it define a sustainable post-2017 risk or cost allocation framework. Overall, the bill does set up a mechanism for cost recovery through securitized bonds in certain circumstances, but there are still many regulatory uncertainties on when and to what extent those bonds will be used.

As of this report, all utilities and many other interest groups have filed comments on how to implement the SB 901 customer harm threshold test for maximum disallowed costs.[76] There is wide disparity of opinion about the scope of protection this should provide, and very few specifics

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71 "Rating Action: Moody's Downgrades Pacific Gas & Electric Company to Baa1 from A3 and PG&E Corporation to Baa2 from Baa1; Rating Outlooks Remain Negative," Moody's Investor Service, September 6, 2018.

72 "Rating Action: Moody's Downgrades Southern California Edison to A3 from A2 and Edison International to Baa1 from A3; Outlooks Stable," Moody's Investor Service, September 6, 2018.

73 *Id.*

74 "Fitch Downgrades Pacific Gas & Electric and PG&E Corp IDRs to 'BBB'; Outlook Negative," Fitch Ratings Inc. press release, September 13, 2018.

"Fitch Downgrades Edison Int'l and Southern California Ed IDR to 'BBB+'; Outlook Stable," Fitch Ratings press release, September 13, 2018.

75 Additional credit downgrades have followed. In January 2019, S&P Global downgraded SCE from BBB+ to BBB. *See* Usman Khalid, "S&P downgrades SDG&E, SoCalEd, Edison International on wildfire, climate risk," January 22, 2019, S&P Global Market Intelligence, accessed February 2019, https://www.spglobal.com/marketintelligence/en/news-insights/trending/NaiINRvWoP7CkJgiOoSjIQ2.

In March 2019, Moody's further downgraded SCE and Edison International from A3 and Baa1 to Baa2 and Baa3, respectively. Fitch also further downgraded SCE from BBB to BBB-, citing the "risk of large incremental catastrophic wildfires in 2019 and beyond, and associated outsized third party liabilities, given an uncertain path to full recovery of wildfire-related liabilities on a timely basis under S.B. 901." *See* "Rating Action: Moody's downgrades Edison International to Baa3 and Southern California Edison to Baa2; outlooks negative," Moody's Investors Service, March 5, 2019; "Fitch Downgrades Edison Int'l and So California Edison to 'BBB-'; On RWN," Fitch Ratings Inc. press release, March 11, 2019.

76 California Public Utilities Commission, *Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)*, Rulemaking 18-10-007 (Filed October 25, 2018).

about possible financial tests.[77] Also, in doubt/debate are the extent to which such guidelines can or will be extended to future possible wildfire costs. While this is a desirable and important policy discussion, it is sufficiently unresolved as to provide no reduction yet in the uncompensated asymmetric risk California utilities are facing.

[77] A CPUC Staff Report to be published on April 5, 2019 should provide more detail on the metrics to be used to evaluate a utility's "financial status" and determine ratepayer harm. See California Public Utilities Commission, *Order Instituting Rulemaking to Implement Public Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901 (2018)*, Rulemaking 19-01-006, Assigned Commissioner's Scoping Memo and Ruling, March 29, 2019, pages 6–7.

III. Compensating Utility Risk Under the Status Quo

Regulated utilities can be risk-intermediaries for megafire mitigation and recovery, but that requires clear guidelines for how to pursue risk management, plus a reliable mechanism for cost recovery, much like financial hedging needs this clarity.

Regulated investor-owned utilities are powerful agencies for financing, investing in, and maintaining public infrastructure. Utilities can also be effective intermediaries for cost socialization relating to public goods and public costs, planned or otherwise (though at some point that can distort the price signaling about the value of its core services). It thus makes sense for a regulated utility to provide some degree of financial resiliency after major crises, by smoothing extreme spikes in costs to make them more bearable for utility customers, and by holding and managing the financial tools to do so.

However, regulated utilities cannot be used for systematically and one-sidedly transferring risks inherent to a public good or geography *away* from customers or taxpayers and *to* the utility investors, without violating the public/private bargain implicit in the regulatory compact. Under this arrangement, investors in a private company agree to finance and maintain public infrastructure and act as risk intermediaries, in exchange for a regulated profit (rate of return). Indeed, no risk intermediary in any industry can be viable for long if it is expected to provide a financial safety valve of absorbing the costs when adverse outcomes occur. At best, it can bear that risk if it is compensated adequately both in advance and steadily over time for being exposed to such potential costs and then be allowed to smoothly and equitably distribute any residual costs after an event takes place. In the immediate context, largely unpredictable wildfires near high-value property are a fact of life in California, and no utility can eliminate that as a cost of living in that region. Failing to appreciate this can have catastrophic financial implications for the utility, which, in turn, would hinder its ability to serve as a public vessel and ultimately harms customers.

The 2000–2001 California Power Crisis is a striking example of a break in the regulatory compact. The investor-owned utilities were expected to purchase power for customers at exceedingly high unhedged wholesale prices in what became a dysfunctional market, but they were not allowed to pass those costs on to customers in a financially viable manner due to retail rate freezes designed to protect customers. The utilities were forced to procure an enormous amount of debt to finance their shortfalls, and their financial health was seriously harmed. In particular, PG&E filed for bankruptcy after it was estimated that it had incurred $9 billion in unrecovered power costs.[78]

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78 "Subsequent Events California's Energy Crisis," U.S. Energy Information Administration, n.d., accessed April 2018, https://www.eia.gov/electricity/policies/legislation/california/subsequentevents.html.

A. The General Problem of Asymmetric Risk for Regulated Companies

Regulated utilities face a "heads I break even, tails I lose" risk exposure which has become critically acute for California utilities due to megafires.

Every regulated utility faces some amount of asymmetric risk. Investors must accept the real, but usually slim, possibility that they will take a financial hit from disallowances or losses after an unforeseen negative event, and that the chances for offsetting financial boosts of the same magnitude are even more remote. Ratemaking generally is based on normalized recent past or coming-year projected operations, with rates set to cover those costs at the expected volume of sales, with no material contingencies built into the allowed costs or returns.[79] If they sometimes lose when worse conditions occur but cannot make an excess return if those conditions do not arise, utilities will face a "heads I break even, tails I lose" risk exposure under regulated operations. Ideally, that asymmetric risk is rather slight in likelihood or consequences; however, the extreme scale of potential wildfires makes such asymmetries dramatic and untenable.[80]

It is perhaps not obvious that such asymmetries are not a normal type of risk for utilities that is already implicitly compensated in their allowed cost of capital. After all, those allowances are derived from financial models that assume markets are efficient and reflect available information, so surely investors have foreseen this problem and priced it into their required returns.

> **Asymmetric** risks of megafires to a utility arise from uncompensated cost exposure that is effectively unbounded, even after net insurance proceeds and stipulated recovery from customers.

Surprisingly this is not the case: These asymmetric exposures are basically like insurance risks and not ordinary business risks. Insurance risks involve loss, unless you are paid to cover those risks (which utilities are not). Insurance risks reduce the expected cash flows from an asset, but they are not accompanied by any prospect of compensatory upside returns such as might be expected from a private sector business investment that can be electively pursued only if/when conditions are favorable. For instance, if your house is newly discovered to be in a flood or earthquake zone, it will lose value, and thereafter it will not appreciate back to some level that compensates you for that loss. In particular, it will not

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79 Under the CPUC, SCE's ratemaking is based on a future test year.

80 Some risks utilities face are fairly symmetric, such as the possibility that loads will be a bit below or a bit above the forecast (though demand-side resources are eroding that confidence). But some risks are more likely to be lopsided such as a plant development exceeding its budgeted costs with a cap on the allowed value if the plant is expensive, but marking it to actual cost for ratemaking if it should come in below budget. Here, the risks of having fire damages imposed that were not in allowed rates in the first instance, and for which there is no extra, reward money when fires do not occur, is clearly asymmetric.

appreciate more than homes that are not so situated; you cannot expect future home buyers to somehow undo that inconvenient discovery. Likewise, when a utility stock faces an asymmetric risk such as the increasing exposure to wildfire liability in California, its stock price will fall (as happened to both PG&E and SCE). However, that stock will not be expected thereafter to appreciate more than similar utilities that do not have that problem, and so shareholders will not have the opportunity to cover the unexpected loss. Correspondingly, the market-required return estimated by applying quantitative models (such as the Capital Asset Pricing Model ("CAPM") and the Discounted Cash Flow ("DCF") model) to a proxy group of other utilities does not capture a premium for all asymmetric risk. So when that measured rate of return is allowed against the equity in rate base, shareholders are not compensated for such exposures. With time and after extreme risk exposures become realized costs, some amount of additional risk may be internalized in markets and in the financial data supplying these models. It is not likely for asymmetric risk to be estimated and calibrated accurately by CAPM or DCF to offset the potential cost of megafires. Appendix A provides a more detailed discussion of how capital market models generally fail to price asymmetric risk.

Failing to recognize this gap caused by asymmetric risk has several adverse consequences. First, it means the utility does not have a fair expectation of achieving its allowed cost of capital, violating principles of regulatory design. This can lead to impaired financial health or more limited access to capital, ultimately interfering with the quality, cost, or pace of introduction of other utility services. In addition, the lopsided exposure to any specific type of asymmetric risk can make the utility managers and investors unduly sensitive to this type of risk compared to all others. They may choose to mitigate it in a way that is not efficient in relation to other risks or other services of importance.[81] Thus, there is "no free lunch"– customers cannot win, in the long run, from penalizing a utility in bad outcomes and not giving it an offsetting opportunity for gain if and when adverse conditions do not occur. There are many possible means of providing this opportunity, or for altering the risk-sharing arrangement so that it does not have unintended, adverse side effects on the rest of utility operations. These means are discussed in the final section of this paper.

If the investor-owned utilities are expected to bear additional asymmetric risk, one helpful mechanism for reducing the adverse effects would involve compensating investors with an increased allowed ROE, well above the market cost of equity. The required increase would reflect the annualized risk, to the extent known, of the share of expected property damage risks from fires that a utility might be asked to bear without socialization in rates. The required increase could be larger than that expected amount, to the extent the utility is seeking (and regulators and customers want) a high probability of financial resilience for the utility, should a larger than typical fire occur sooner than expected.[82]

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81 For instance, the most exposed or lopsided risk may get disproportionate attention even if it is not the largest or most easily mitigated risk.

82 Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, *Risk and Return for Regulated Industries* (London: Academic Press, 2017), Chapter 10.

B. Illustrative Risk Compensation via Return on Equity

An incremental adjustment to ROE would address asymmetric risk, but it would be hard to estimate and might not be fully protective.

A regulated utility's allowed return on equity is typically a point of considerable debate in ratemaking proceedings. The ROE essentially determines how much the utility earns for investing in assets necessary to provide service to customers. Over the past two and a half decades, the CPUC, for example, has granted SCE ROEs ranging from today's 10.30% to 12.65% in the 1990s—declining over time in conjunction with declining interest rates.[83] The largest change in SCE's approved ROE during that time was from 12.65% to 11.6% and from 11.5% to 10.45%, both a reduction of 1.05% (105 basis points). Great care is devoted to quantifying the fair rate of return, sometimes with heated disputes over 25-50 basis points. In contrast, the megafire-related financial risks faced by the California utilities would require incremental ROE adjustments potentially much higher than 1%, as we demonstrate in this section.

SCE's total equity rate base under both CPUC and FERC jurisdictions is about $18.0 billion.[84] Therefore, as a rule of thumb, 100 basis points of an ROE spread across the total rate base equates to almost $180 million. This makes it immediately apparent that the potential billions of dollars of exposure that SCE shareholders may face in the future for each extreme event could have very dramatic implications if translated into an asymmetric risk adjustment under this traditional ROE paradigm.

1. The Range of Potential ROE Increases

Depending on SCE's executive managers' and investors' perception of financial risks, an appropriate incremental risk adjustment to ROE could be substantial.

Figure 4 demonstrates the magnitude and range of the required ROE increase, depending on the anticipated scale of annual megafire events (in steps of billions of dollars) and the anticipated likelihood of their annual occurrence (in %) that it would cover. For illustration, the expected liability from a fire like the Thomas Fire (estimated by Fitch to cost around $4 billion)[85] occurring once every four years would be $1 billion. The table entries within Figure 4 represent the SCE

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83 "Rate Case History," S&P Global Market Intelligence, February 2019.

84 Equals $34.6 billion total 2020 rate base times SCE's 52% equity ratio. *See* Edison International, "Business Update: February 2018," February 23, 2018, page 10, accessed February 2019, https://www.edison.com/content/dam/eix/documents/investors/events-presentations/eix-february-2018-business-update.pdf.

85 "Fitch Maintains Southern California Edison & Edison International on Rating Watch Negative," Fitch Ratings, August 23, 2018, accessed February 2019, https://www.fitchratings.com/site/pr/10042429.

ROE increase needed to offset that size and likelihood of annual events. The ROE increases are calculated based on SCE's total equity rate base of $18.0 billion.

Figure 4: ROE Increase Depending on Anticipated Financial Burden
Calculated based on SCE's total equity rate base of $18.0 billion

Anticipated Net Cost of Event to Utility ($B)	Probability of Event per Year		
	10%	20%	50%
$1	0.6%	1.1%	2.8%
$2	1.1%	2.2%	5.6%
$3	1.7%	3.3%	8.3%
$4	2.2%	4.4%	11.1%
$5	2.8%	5.6%	13.9%
$6	3.3%	6.7%	16.7%
$7	3.9%	7.8%	19.5%
$8	4.4%	8.9%	22.2%
$9	5.0%	10.0%	25.0%
$10	5.6%	11.1%	27.8%

Note: Net cost represents costs to utility shareholders, that is, net of insurance payouts and cost recovery, if any, from customers.

Figure 4 shows how the expected cost (size in row multiplied by probability in column) of a hypothetical megafire event quickly becomes a very large supplemental ROE requirement. A given size increase could be sufficient to cover several different combinations of events and likelihoods. For instance, a 5.6% increase is enough for a $10 billion risk with a 10% chance, or a $2 billion event with about a 50% chance. In monetary terms, a 5.6% increase would be about $1 billion per year, not enough to fully cover either of these events unless they occurred a few years after the ROE allowance had been in effect.

Figure 4 is just a display of ranges showing how large the ROE equivalent of the expected costs of large fire risks can be. It does not reflect actual estimations of risk exposure or empirically observed insurance costs. Below we further characterize where SCE could fall in the matrix shown in Figure 4 by reviewing SCE's 2018 RAMP analysis and potential additions to it, as well as observed indications about how the insurance industry has priced wildfire risk.

a) *Estimated Magnitude of Wildfire Exposure*

SCE RAMP Analysis. SCE's 2018 RAMP analysis is informative for exploring scenarios where the utility must plan on covering a large range of potential wildfire damage each year. Specifically, the RAMP analysis is intended to establish an expected statistical pattern of wildfire occurrence and severity, associated economic and other damages resulting from this set of wildfires, and cost-effective mitigation in relation to other kinds of risks the utility faces that also merit anticipatory prevention or mitigation.

The SCE RAMP analysis uses wildfire data from 2015-2017 and an average sample of 44 wildfires per year attributed to utility distribution equipment to assess its associated wildfire ignition risk, derived from wildfire history in its territory based on CPUC Reportable Incident listings and CPUC High Fire Risk Area maps. More specifically, SCE reviewed the history of distribution-related wildfires in high-risk areas of its territory from 2015-2017 and developed a sample with an average of 44 fires per year. From this sample, SCE modeled a probability distribution of potential likelihoods and costs from property and other losses, based on historical probabilities of fires of different sizes and circumstances occurring, and potential damage costs from each class of fires based on an exponential distributions[86] The modeling consisted of running a Monte Carlo simulation against these distributions of past events for 10,000 trials, with RAMP results ranging from damages of zero to a worst-case level of about $7.1 billion, each with a probability of 1/10,000 (or 0.01%).

This $7.1 billion extreme is indicative of the level of insurance (or risk compensation) SCE might need to expect over time to cope with very bad fires. Other measures of risk from this analysis included a mean loss across all 10,000 simulated fire-years of $219 million and an expected loss for the worst 10% of outcomes of $1.42 billion.

Additions to RAMP. For this report, we augmented the SCE Monte Carlo analysis in two ways: First, we extended the cost data on the size and financial consequences of large fires by adding 10 fires to the cost data base that occurred since the SCE data set was compiled.[87] These were all fires occurring in 2017 and 2018 that were larger than 5000 acres, including the deadly Camp Fire and the contemporaneous Thomas and Woolsey fires in the SCE territory. These increased the length of the "tail" of extreme cost outcomes that were possible.

Second, because there have been relatively few extremely large fires (despite being very dramatic), even a Monte Carlo simulation with 10,000 simulated years may end up having an outcome of largest events that is not particularly stable across repeated 10,000 year simulations. (This is a general problem with forecasting rare, "black swan" events, for which the "typical" costs or frequencies are not well understood precisely because they are rare and idiosyncratic in size and impact.) We addressed this by simulating 10,000 fire-years 100 times, then taking the average of all of those to obtain a more robust estimate of the large fire outcome possibilities. These additional Monte Carlo runs were done with the cost data extended through 2018. The combined effect of these extensions is to find a new worst case of $13.61 billion and a mean loss of $507 million pre-tax—both much larger than the 2018 RAMP analysis but understandable in light of including the Camp Fire that may have cost $15 billion or more.

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86 The exponential distribution is applicable to fire costs because it cannot be negative and it has a very long "tail" for the low probabilities of very high cost events.

87 These were all large (greater than 5,000 acre) fires because these fires have the greatest financial significance: Thomas, Rye, Camp, Woolsey, Boot, Stone, Donnell, Whaleback, Delta, and Pawnee.

b) *Insurance Industry Benchmarks*

The private insurance industry is organized and experienced to price the risk of natural disasters, so the cost and nature of their services in the California setting provides useful context for the costs of self-insuring as discussed above. A key challenge, of course, is that the industry has not actually priced exposures of the dollar magnitude implied by recent megafire experience. Still, extrapolation from visible data points on insuring parts of more "ordinary" disasters suggests annual costs of $1 billion or more for fires.

Catastrophe Bonds. Recent data based on PG&E experience is available for this purpose. In 2018, PG&E increased its coverage for third-party property damage due to wildfires through the reinsurance market, where a $200 million catastrophe bond issued by Cal Phoenix Re was used to fund the insurance (the "Cat Bond").[88] The Cat Bond was offered to Cal Phoenix Re investors with a fixed spread to LIBOR of 7.5%, effectively representing the insurance premium.[89] We understand that this was the first Cat Bond of its kind, *i.e.*, the first written for company-specific wildfire damages in the context of inverse condemnation liability exposure in California.[90] More commonly, catastrophe bonds have been issued for relatively more diversified insurance company exposure to hurricanes, earthquakes, and other more familiar and widely occurring large disasters than the California megafires.

Based on information from the Offering Circular, the Cat Bond was structured to cover approximately 40% of a band of residual risk after the first $1.25 billion of realized loss up to $1.75 billion, and they were specifically targeted to third-party property damage. This $500 million loss "layer," in which the Cat Bond investors participate up to $200 million, covered events with a statistically expected loss rate of approximately 1%.[91] The expected loss rate was derived via a detailed model of California wildfire risk potentially affecting PG&E's service territory prepared

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88 Cal Phoenix Re Ltd., *Confidential Offering Circular Supplement No. 1*, July 30, 2018 ("Offering Circular").

89 Bloomberg. Catastrophe bonds have developed in recent years as a mechanism for insurance companies to access deeper pools of capital and diversify exposure. They consist of securities issued to pre-fund the costs of specifically identified risks (such as wildfires affecting PG&E). If the specified events occur, the funds are used to pay associated costs, but are otherwise repaid to the investors (with interest), like conventional bonds. Interest payments on catastrophe bonds in excess of risk-free rates can be likened to insurance premiums on the specified catastrophe risks, since they form the bulk of compensation to investors for bearing them.

90 Shortly after PG&E obtained its Cat Bond, Sempra Energy, the parent company of SDG&E, followed suit with a $125 million catastrophe bond issued by SD Re offered to investors with a coupon price of 4%. *See* "SD Re Ltd. (Series 2018-1)," *Artemis* Deal Directory, accessed February 2019, http://www.artemis.bm/deal-directory/sd-re-ltd-series-2018-1/.

91 Expected loss rate is the average or expected loss of claims inside the insured range, expressed as a percentage of maximum coverage. This is a standard metric used by the Cat Bond industry to allow comparisons across different kinds of risks.

by AIR Worldwide Corporation ("AIR").[92] This model was prepared by AIR for Cal Phoenix Re in connection with the Cat Bond.

As was shown above, the total exposure from megafires could reach several billion dollars, which was greater than the amount raised by Cal Phoenix Re through the Cat Bond. One method of extrapolating the cost of the Cat Bond to the full extent of potential wildfire exposures was to combine the following:

1) *Total exposure* to third-party property damage beyond the $500 million layer covered by the Cat Bond and the corresponding expected loss (based on the AIR model);

2) An appropriate *premium,* based on publicly available data for a broader universe of catastrophe bonds at varying levels of expected loss, with an adjustment for the newness and thinness of wildfire coverage of this magnitude and basis for liability exposure.[93]

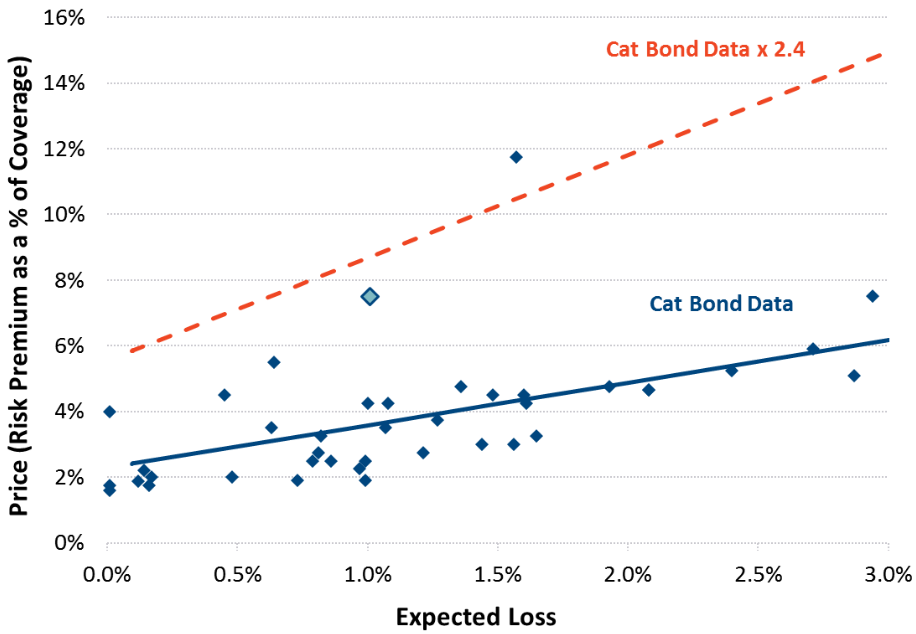
Catastrophe bonds involve creditors loaning funds on behalf of the insured company with an interest rate that includes a default premium for the possibility that the loan will not be repaid but instead will be used to service claims against the underlying type of catastrophe, if it occurs. Thus, a portion of the interest rate is effectively the cost of the insurance per dollar of potential loss. Recent compilations of catastrophe bond price and expected loss data on 56 catastrophe bonds (for various types of non-California fire catastrophes) issued in 2018 and early 2019 provided by *Artemis* indicate that their investors have recently required risk premiums between 1.9% and 4.25% on bonds having expected loss rates around 1%.[94] A linear regression of this catastrophe bond data (presented as blue diamonds) is shown below by the solid blue line in Figure 5, with a premium of 3.6% corresponding to an expected loss of 1%.

92 Per the bond documentation, "AIR, established in 1987, is independent software and consulting firm that develops catastrophe risk assessment and management methodologies and techniques." Offering Circular.

93 Based on transaction data compiled by *Artemis* (http://www.artemis.bm/).

94 *Artemis* is a news, analysis and data media service focused on catastrophe bonds and insurance linked securities. 39 of the 56 catastrophe bonds were in evidence at the time of a similar report prepared for PG&E in 2018. *See* Frank Graves *et al.*, "California Megafires: Approaches for Risk Compensation and Financial Resiliency Against Extreme Events," October 1, 2018, page 29.

Figure 5: Cat Bond Premium per Dollar of Covered Loss



Source: *Artemis* Catastrophe Bond & Insurance-Linked Securities Deal Directory, accessed March 2019, http://www.artemis.bm/deal_directory/.

Importantly, however, the universe of catastrophe bonds covered by *Artemis* does not reflect California wildfire risk under inverse condemnation, because as noted above, this is a new application of catastrophe bond financing. The 7.5% rate PG&E actually incurred on the Cat Bond (for its coverage of a $200 million tranche for up to 40% of damages between $1.25 and $1.75 billion, shown as a light blue diamond in Figure 5 above) falls well above the range for non-wildfire catastrophe bonds at the same level of 1% expected loss—about 2.4× as high as would have been predicted for more conventional catastrophes at the time of issuance.[95] This may be attributable to the relative novelty of California wildfire bonds, with correspondingly thin market capacity to absorb this kind of risk. It may also be because, for any given level of expected loss, investors are unfamiliar with the potential distribution of outcomes and concentration of losses in the case of wildfires. We assume that for the purposes of this analysis it is a persistent feature of pricing for California fire insurance. The red line in Figure 5 above shows the original Cat Bond regression scaled for this markup above more conventional catastrophes.

Applying this level of premium to much larger wildfire coverage amounts than were observed in the AIR sample (reaching into billions of dollars of rare but possible exposure) is likely conservative. If such extreme coverage were available at all, it is likely that a larger premium would be required in current markets, simply from a supply and demand perspective.

95 Catastrophe bonds contemporaneous with PG&E's Cat Bond in 2018 had a premium of 3.1% corresponding to an expected loss of 1%.

Insurance Cost Data. Separately, SCE and other California utilities have reported information about the costs of fire insurance they have obtained in the recent past that is informative about compensating additional risk. The annual financial statement filings of Edison International/SCE and PG&E show that they each carry about $1 billion of wildfire insurance and SCE in particular describes having tranches of insurance costing about 30 cents per dollar of coverage up to the first $1 billion or so of possible losses.[96,97] In its most recent earnings call, SCE mentions securing $750 million in coverage—subject to self-insurance and coinsurance provisions—for a cost $321 million.[98]

In addition, SCE made a Z-factor cost recovery filing in March 2018 that described its insurance coverage strategy: "procuring increasing amounts of coverage and progressively building a 'tower' of overall coverage" to meet its needs.[99] This concept is illustrated below in Figure 6 using estimates of insurance tranche costs informed by the average costs noted above taken from recent transactions and annual reports for California utilities.

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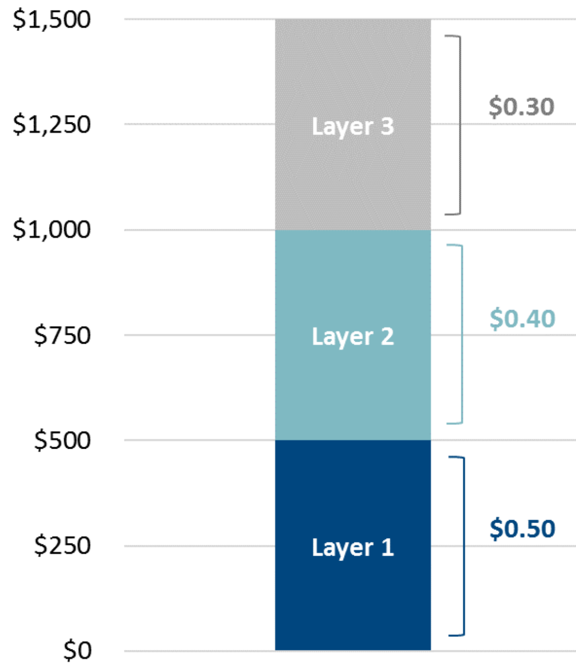
96 Pacific Gas and Electric Company, Form 10-K for the Fiscal Year Ended December 31, 2018, page 33, accessed February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx.

97 SCE's wildfire expense prior to regulatory deferrals was approximately $237 million in 2018 and will be approximately $321 million in 2019 for about $1 billion in wildfire-specific insurance coverage. Cents on the dollar are calculated as the premium divided by total coverage. *See* Southern California Edison, Form 10-K for the Fiscal Year Ended December 31, 2018, page 108, accessed February 2019, https://www.edison.com/home/investors/sec-filings-financials/sec-filings.html.

98 Southern California Edison, "Prepared Remarks of Edison International CEO and CFO: Fourth Quarter and Full-Year 2018 Earnings Teleconference," February 28, 2019, page 12, accessed March 2019, https://www.edison.com/content/dam/eix/documents/investors/events-presentations/eix-fourth-quarter-2018-CEO-CFO-earnings-call-remarks.pdf.

99 Advice Letter 3768-E, "Request for Z-Factor Recovery of the Revenue Requirement Associated with Incremental Wildfire-Related Liability Insurance," March 14, 2018, page 3.

Figure 6: Illustrative "Tower" of Insurance Coverage



Together, these materials show two things: First, the cost of covering the initial level of risk, *i.e.*, zero to $0.5 billion or so can be extremely high—here around 50 cents per dollar of coverage on average, which indicates that the perceived likelihood of a claim that large is around that same percentage, *i.e.*, possibly 50%. Second, the cost per layer declines (per dollar of coverage) as additional, more subordinate tranches of insurance are added. That is, the first "floor" in a "tower" of insurance costs the most, with declining costs per floor for each comparably sized layer above that. This of course reflects the fact that the likelihood of moderate sized problems is higher than the likelihood of the largest, worst extremes. We conclude that the first few layers of property liability fire insurance for utilities in California can be supplied by the insurance industry to SCE or a similar California utility for roughly 50 c/$ for the first $500 million, 40 c/$ for the next $500 million, and 30 c/$ for a layer after that covering $1–$1.5 billion. Of course, perceived risks and resulting costs are changing over time, so these are more indicative than precise, but they capture the high cost and its overall sensitivity to what level of risk is being considered.

Combining the Cat Bond Data and Utility Insurance Price Levels. The above insurance prices apply only to the lowest levels of a tower of insurance for wildfire exposure, not informing what it would cost to cover higher levels of dollar exposure above $1 billion or so and up to the most extreme events. Indeed, it is unclear that any commercial insurance would be available to cover exposure much above $1.5 billion. However, insurance principles and practices for pricing a variety of relatively rare events can still be used to estimate the cost of extreme fire insurance coverage in theory. As discussed above, for this purpose we used empirical observations from the Cat Bond market to relate expected loss rates to costs of insurance. As explained below, these bond rates (insurance costs) indicate that expected loss levels up to 2% or so would entail insurance costs up to approximately 12% of the worst loss being covered, as was shown previously in Figure 5. Such pricing can then be applied to any type of insurance or level of dollar coverage for which the expected loss rates are known (or can be estimated).

Unlike Cat Bonds, the insurance pricing information on past coverage obtained by California utilities is not characterized explicitly in expected loss terms. However, it is reasonable to assume that the insurers were offering those recent prices based on a perception of risks that included the most recent 2018 fires, similar to range of possible outcomes we found with the augmented SCE RAMP probability distribution described above. On this basis, insurance-like obligations for specified levels of dollar coverage can be converted into expected loss terms, utilizing the cost distributions obtained from Monte Carlo simulations of the 10,000 fire-year cost distributions.

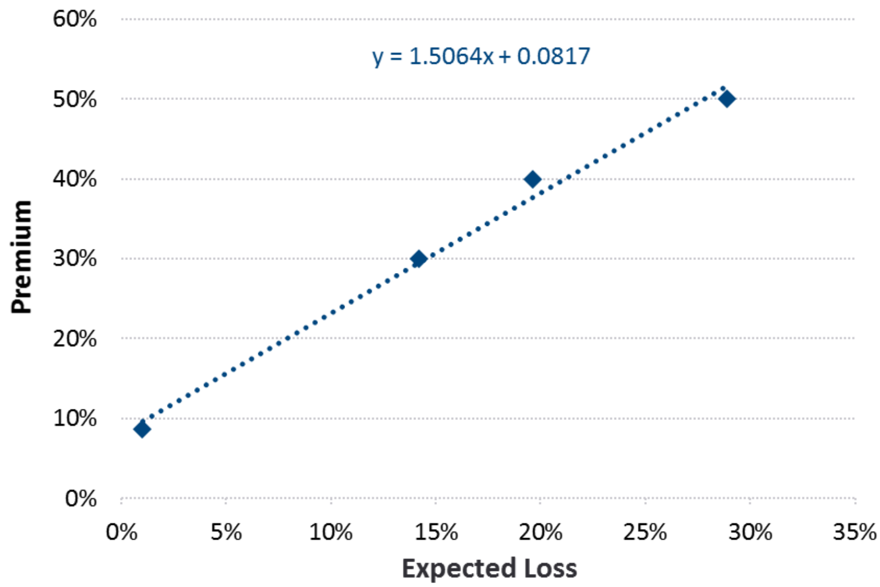
This conversion to expected loss terms allows us to use the two kinds of insurance pricing information—Cat Bonds and conventional utility insurance—on an "apples to apples" basis. This combination is summarized this in Figure 7 below, which depicts the relationship between the Cat Bond and insurance premiums as a function of expected loss. That is, Figure 7 plots insurance premiums per dollar of worst-case coverage on the y-axis against expected loss on the x-axis. These produce a relatively linear pattern of increasing costs per dollar of coverage as the expected loss rates increases (or equivalently, declining price per dollar of coverage as the expected loss decreases towards more rare, extreme events).

Since this marginal cost is declining for more remote events, the average cost to cover all the risk from, say $1 billion, to any progressively higher limit also declines. With this full range of prices at different levels of expected loss, we can estimate the costs of covering any layer of risk in the Monte Carlo simulations that SCE or Brattle have conducted.

The relationship between insurance cost and expected loss [in the middle ranges of exposure] can be characterized by the linear equation:

$$Insurance\ Cost = 8.17\% + 1.5064 \times Expected\ Loss$$

Figure 7: Relationship between Expected Loss and Assumed Insurance Premiums



c) SCE's Exposure and Needed Compensation

We have combined 1) the estimated magnitude of wildfire exposure from Monte Carlo outcome simulations with 2) the insurance industry pricing benchmarks described above to develop estimates of SCE's exposure and needed compensation. This takes the following form:

1) Measuring expected loss factors corresponding to segments of the probability distributions underlying SCE's fire risks at various thresholds (*e.g.*, mean, "tail average", 99th-percentile, maximum) based on SCE's RAMP analysis (augmented as described above for more risk simulations and more recent fire data), and

2) Deriving implied insurance costs corresponding to those segments based on the relationship between insurance cost and expected loss depicted above in Figure 5 and Figure 7

One potentially mitigating consideration is that if SCE were to face damage claims, we expect they would be tax deductible, reducing them by about 28%. For simplicity, we have made the assumption that SCE would have enough other income to fully utilize those deductions, regardless of the scale of the event. Thus, the expected cost of insurance coverage for whatever portion of the fire risk distribution SCE management chooses to bear would be offset by the value of the expected tax shield in the event of an actual claim, resulting in a somewhat lower number.[100]

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[100] However, it is not hard to imagine a scenario in which SCE could not apply the wildfire claim against other taxable income for any given year, in which case the benefits of tax deductibility would be deferred and the worst case impact would initially be greater.

These calculations are shown in Figure 8 and Figure 9 below, where column [a] shows the simulated wildfire damages before existing insurance or other mitigation and column [b] shows the damages net of $1 billion in existing insurance (effectively, the policy size for incremental insurance). Column [c] shows the expected loss rate (as a percent of the limit or max insurance equal to the row label) for the Net Exposure in column [b], and column [d] shows the cents per dollar of coverage up to that level (where those prices are derived from the preceding linear price graphs in Figure 5, based on the Cat Bond market, and Figure 7, based on the combined CAT Bond and utility insurance coverage estimates). Column [e] multiplies those costs per dollar by the Net Exposure in column [b] to get the total annual cost, shown in billions of dollars. This insurance-equivalent cost is offset in column [f] by the 28% expected tax shield obtained from the deductible expected losses at that level of coverage. Finally, this dollar amount is expressed in column [g] as a percentage of SCE's 2020 $18.0 billion equity portion of its rate base as projected in its most recent GRC. This column is equivalent to the additional after-tax ROE allowance SCE would require, above and beyond its normal cost of capital, to cover any row's level of potential after-tax damage claims. In order for SCE to receive this much after tax, the amount in column [g] would have to be grossed up for income taxes, just like normal return on equity allowances, shown in column [h].

Figure 8: Cat Bond-Implied ROE to Reflect Wildfire Risk ($ Billions)

	Brattle Simulated Damages	Net Total Exposure	Expected Loss	Cents on the Dollar	Insurance Cost	Insurance Cost Less Tax Shield	Implied ROE	Revenue Requirement
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]
Median	$0.00	-	-	-	-	-	-	-
Mean	$0.51	-	-	-	-	-	-	-
*Mean Above $1B	$2.60	$1.60	10.45%	38.2	$0.61	$0.44	2.44%	$0.61
95th Percentile	$2.91	$1.91	9.64%	35.7	$0.68	$0.49	2.73%	$0.68
**Tail Average	$3.40	$2.40	8.55%	32.3	$0.78	$0.56	3.10%	$0.78
98th Percentile	$4.38	$3.38	6.87%	27.0	$0.91	$0.66	3.66%	$0.91
99th Percentile	$5.47	$4.47	5.55%	22.9	$1.02	$0.74	4.10%	$1.02
Maximum	**$13.61**	**$12.61**	**2.09%**	**12.1**	**$1.53**	**$1.10**	**6.11%**	**$1.53**

Sources and Notes:

[a]: Reflects average financial damages from Brattle 2010-2018 simulations.

[b]: Net total exposure assumes one billion dollars of insurance already in place.

[c]: Expected loss operates on the net total exposure.

[d]: Premium associated with given expected loss, based on Cat Bond premiums.

[e]: [b] x [d].

[f]: [e] x (1 - 28% tax rate).

[g]: [f] / equity rate base. The equity rate base is calculated as $34.6 x 52%.

[h]: [f] / (1 – 28% tax rate).

Figure 9: Insurance Tower-Implied ROE to Reflect Wildfire Risk ($ Billions)

	Brattle Simulated Damages	Net Exposure	Expected Loss	Cents on the Dollar	Insurance Cost	Insurance Cost Less Tax Shield	Implied ROE	Revenue Requirement
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]
Median	$0.00	-	-	-	-	-	-	-
Mean	$0.51	-	-	-	-	-	-	-
*Mean Above $1B	$2.60	$1.60	10.45%	23.9	$0.38	$0.27	1.53%	$0.38
95th Percentile	$2.91	$1.91	9.64%	22.7	$0.43	$0.31	1.73%	$0.43
**Tail Average	$3.40	$2.40	8.55%	21.0	$0.51	$0.36	2.02%	$0.51
98th Percentile	$4.38	$3.38	6.87%	18.5	$0.63	$0.45	2.51%	$0.63
99th Percentile	$5.47	$4.47	5.55%	16.5	$0.74	$0.53	2.96%	$0.74
Maximum	**$13.61**	**$12.61**	**2.09%**	**11.3**	**$1.43**	**$1.03**	**5.71%**	**$1.43**

Sources and Notes:

[a]: Reflects average financial damages from Brattle 2010-2018 simulations.

[b]: Net total exposure assumes one billion dollars of insurance already in place.

[c]: Expected loss operates on the net total exposure.

[d]: [c] x 1.506 + 0.082. 1.506 is the slope of the linear relationship to insurance and 0.082 is the y-intercept.

[e]: [b] x [d].

[f]: [e] x (1 - 28% tax rate).

[g]: [f] / equity rate base. The equity rate base is calculated as $34.6 x 52%.

[h]: [f] / (1 – 28% tax rate).

Per this calculation, if SCE were to replicate insurance-like coverage for up to $12.61 billion—which is its average worst case outcome across 100 10,000-fire-year simulations after $1 billion of actual third party insurance—it would need between $1.0 and $1.1 billion of incremental net income to compensate for the risk. This could correspond to a 611 basis point addition (based purely on Cat Bond data) or a 571 basis point addition (based on observed CAT bond and combined CAT bond and utility insurance coverage estimates) to its normal ROE.

However, it is important to not over-dignify the precision of these calculations. As shown in Figure 10, if cost distributions are varied simply by using the lowest or highest of the 100 10,000 fire-year Monte Carlo simulations, the maximum outcome spans a nearly $10 billion range, from $9.98 to $19.65 billion. The associated required ROE supplement would vary from 514 basis points to 765 basis points (based purely on Figure 5) or from 445 basis points to 779 basis points (based on Figure 7). Further variation would arise in these estimates if even a just a few more or different fires were included in the cost or ignition samples. Thus, an ROE more consistent with the level of precision, and in the middle of this sensitivity range, would be 600 basis points, suitable for covering around $15 billion of pre-tax claims.

Figure 10: Alternative Distributions

	Maximum Outcome ($ Billions) [1]	Incremental Wildfire ROE (Cat Bonds) [2]	Incremental Wildfire ROE (Insurance Tower) [3]
Low of 100 Simulations	$9.98	5.14%	4.45%
Average of 100 Simulations	**$13.61**	**6.11%**	**5.71%**
High of 100 Simulations	$19.65	7.65%	7.79%

Sources and Notes:

[1]: Worst outcome out of 10,000 trials.

[2]: Dollar-cost of insurance (reduced by tax rate of 28%) based on Cat Bond premiums.

[3]: Dollar-cost of insurance (reduced by tax rate of 28%) based on observed CAT bonds and utility insurance coverage estimates.

In addition, it is important to stress that there is no necessary or definitively correct amount of incremental ROE for SCE or any utility to seek as compensation for bearing this kind of risk. This can be appreciated when one considers that even the 600 basis points derived above for the worst case scenario is sufficient only in a statistical sense. It could easily be inadequate for an actual megafire event. This is because SCE is facing this problem without being structured as a true insurance company, and could in any particular year bear losses far beyond the incremental ROE. It could be the case that neither the utility regulators nor its managers should expect or prefer the utility to be responsible for bearing an arbitrarily large amount of such risk: It would be perfectly reasonable to conclude that the utility should only stand ready for problems up to some serious but limited maximum scale, recognizing that the ultimate size and consequences of a fire are probably uncontrollable even if the risk of fires starting can be reduced. Such limits may be important for financial market confidence, and they would also affect intertemporal issues of how different groups of customers pay for the fire risks over time.

In general, when an entity must self-insure, it is necessary to be more conservative than the annualized statistical risk would require. This is easily seen by looking at personally funded retirement planning: Suppose you plan your annual savings based on a statistically-expected average lifespan of 80 years, but you live to be 100 years old. That outcome, while presumably attractive for non-financial reasons, would likely be a tragic failure in terms of your financial planning unless you had prepared for a "worse" (longer life) case than is typical or actuarially likely. A diversified life insurance company (*e.g.*, selling annuities) does not need to over-insure for longer lives, because with a large pool of customers, some will die before they reach 80 and their assets will fund the ones who live beyond 80. Here, SCE must be compensated for the fact that inverse condemnation effectively makes it an insurance company without having the true financial structure of one. Thus, if the goal of an ROE supplement is to both cover large damages and strongly increase the likelihood of remaining viable after a megafire, SCE needs to either 1) get lucky and not have that event happen until a lot of prior supplemental payments have accrued, or 2) get covered for a bigger than statistically expected risk, or 3) get the statistical amount (per the tables above) but with guarantees that such payments will continue for several years after any fire event, even if that fire occurs early in the policy period.

Thus, we know with certainty what direction of adjustment self-insuring requires, which is a larger ROE supplement. On average, such an increased allowance would over-collect the need, but you would not know that for quite a while. At some point, if no extreme events have occurred, the ROE increases would need to be adjusted downward, and you would need a mechanism for re-investing or managing the cash.

Regardless of how far into the above level of risk exposure SCE prefers to be compensated, or it is allowed to cover, this survey of actual past fire cost property damages and this insurance-type analysis of likely damages both show unequivocally that the expected cost of megafires for SCE is a multi-billion dollar problem, currently uncompensated. This exposure requires at least a multi-hundred million dollar annual allowance to defray the likely realization of costs or to obtain actual insurance coverage (assuming that was feasible). Absent such compensation, or better, some new, not yet established legislative and regulatory protection from incurring such extreme costs, this loss exposure represents an impairment of the utility's ability to recover its full costs, including a fair return on capital. The impairment arises because uncompensated wildfire liabilities create a somewhat unlikely (but possibly huge) loss potential with no upside—a mix which can only bring expected returns below the intended, required rate of return. This is an asymmetric risk not reflected in conventional costs of capital.

2. Limitations of the ROE Approach

The ROE approach could still leave shareholders with residual risk, while creating the mis-impression that they had been fully covered.

Given the large losses an uncompensated liability for wildfires could impose, an ROE increase for the asymmetric risk of megafires has intuitive appeal. It is critical that some offsetting compensation be provided in order to keep the utility financially sound and attractive to investors, and an ROE adjustment is one practical way of doing so. However, protecting utility shareholders in this way can be problematic for a few reasons.

First, and most fundamentally, it is implausible that the required ROE increase can be estimated and calibrated accurately to assuredly offset the potential cost of megafires. While the above calculations show that protecting against the probabilistic risk of megafires can be very costly, even an ROE increase sized at several hundred more basis points beyond these calculations could prove to be inadequate to protect against the cash flow requirements of some plausible scenarios. Indeed, even the 600 basis points that would defray an annual expected exposure of about $1 billion and a very low probability of much larger losses should not be construed as a tight estimate of the statistical annualized cost, as there are many difficult analytical questions and data limitations about how to model the extreme tails of a distribution. The fact that the insurance industry seems to be unwilling to participate beyond a moderate level of risk is strongly indicative of this uncertainty and unfamiliarity. Even if history was very well understood, the risks of megafires appear to be increasing, and the value of the properties that may be exposed is also a moving target depending on how and where the California economy expands.[101]

Second, essentially any ROE supplement will still leave a residual risk concentrated on current shareholders if or when those allowances, even accumulated over time, do not match the immediate realized burden from a megafire. In principle, reliably continuing future allowances for the ROE supplement after a large fire could provide expected cash flows sufficient to gradually compensate (or secure debt financing for recovery from) a large fire and to cover future ones. However, investors are likely to have some skepticism about the continuity of such a policy, especially after a large disaster.

As noted earlier, the existence of an ROE increase may also create the mis-impression for regulators and the public that the utility and its shareholders have been fully compensated for any and all fire risks (notwithstanding the difficulty in estimating the exposure), with no need for additional protection even though a fire might exceed what was expected as statistically plausible in the original design—a "circularity" problem that leaves utilities exposed to the full scale of any unforeseen or mispriced extent of risk.[102]

Finally, it is not at all evident that a vast level of utility cost responsibility for wildfire damages is the best social solution to this ongoing problem that considerably transcends utility operating norms and obligations. Utilities can and should pursue prudent mitigation and obtain or provide some degree of insurance, but this is not a problem that is controllable or eliminable even with extraordinary budgets and prudent practices. It may require much broader means of co-insurance with many utilities and agencies, so that potentially very large costs can be borne without threatening the viability of the electric power providers and without undue concentration of burden on current, unlucky customers who happen to be in the service territories at the time of catastrophic fires. Thus, while an ROE supplement would be helpful and appropriate under current circumstances, it would be more desirable to reach a stronger and more sustainable solution for how to socially plan for and share the costs of fires across as broad a base of customers as possible, as well as for spreading the expected and incurred costs over long time periods. There are many such possibilities that should be considered by legislators and regulators, but their design is beyond the scope of this analysis.

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101 Importantly, the asymmetric risk at issue cannot be assumed to be static over time, since both climate and regulatory trends indicate a growing problem. If wildfires continue to increase in severity, and if the apparent inconsistencies between the application of inverse condemnation and the CPUC's prudency standards remain, then it is also fair to imagine a scenario where the insurance industry and utility customers (via the CPUC) continue and possibly accelerate their flight away from the financial burden.

102 Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, *Risk and Return for Regulated Industries* (London: Academic Press, 2017), Chapter 10.

IV. Conclusions

The extreme potential costs, and apparently growing risk of megafires in California, plus the state's unsettled legal and regulatory approach to assigning financial responsibilities of those events, highlight the need to create mechanisms for managing the risks and costs of extreme events in the state. The practice of inverse condemnation in California courts, abutting against the CPUC's application of traditional prudency standards to megafire cost recovery, may result in material disallowances on the cost recovery of fire damages and has created significant uncompensated asymmetric risk for investor-owned utilities. This is not a sustainable financial model for the state or for utilities. If left unaddressed, this asymmetric risk harms the regulated utilities' ability to fund ongoing normal business and could create severe business disruption.

An ROE allowance for SCE of around 600 basis points, creating additional income of about $1 billion per year, is consistent with the apparent expected and worst likely size of the problem as derived from either the size and cost of recent past fires or from pricing evidence for insurance and catastrophe bonds. This is not to suggest that this is precisely the true or full cost of the risk, but to show that a large amount of new compensation is almost certainly required in order to be roughly commensurate with the problem. Authorizing such an amount on top of the cost of equity (measured in conventional ways and reflecting risk positioning in the industry) would provide monies that offset a material part of the overhanging potential losses from fires. Importantly, such a supplement is needed because it is not part of the ordinary cost of capital but instead it is the amount needed to restore investor expectations of being able to earn the normal cost of capital.

Appendix A: Asymmetric Risk

The asymmetric risk facing an investor in a regulated utility can be analogized to the risk facing an investor in corporate bonds: Although they both have the opportunity to earn a stipulated return (the authorized ROE for a utility and the coupon rate for a bond), there is no guarantee for either and not much upside (though bonds can appreciate if interest rates fall after they are issued), while there is unbounded downside (albeit with low probability). For example, a corporate bond default can wipe out the entire value of the bond. Similarly, a utility investment is exposed to adverse "black swan" events that, while rare by definition, have the potential to severely handicap or even bankrupt the company and similarly wipe out much of its value.

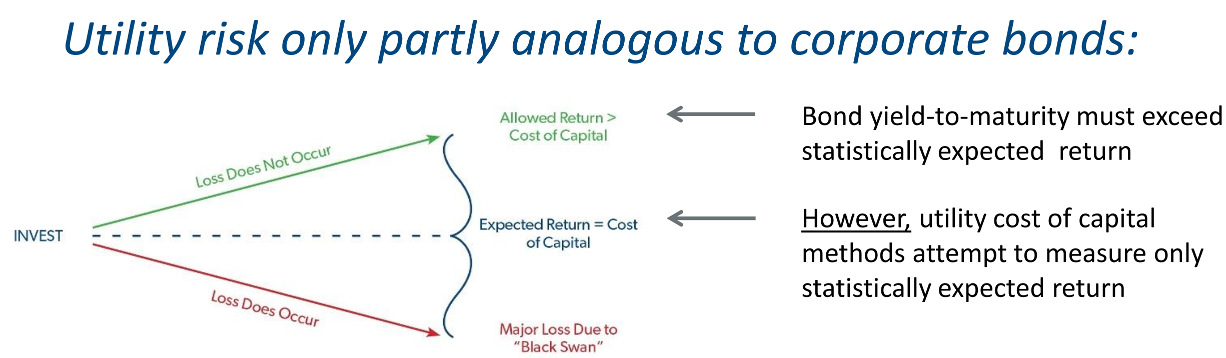
By the nature of the utility business, these adverse events tend to have a strong regulatory flavor, such as:

- The natural gas price deregulation in the 1980s, which pushed two natural gas pipelines into bankruptcy, largely because they held by-passable long-term supply purchase contracts (for resale to distribution customers) that were well above spot market prices (which itself was created by the deregulation).
- The mid-1990s' vertical unbundling and wholesale deregulation of generation in the electric industry, which created significant stranded costs that were not always reliably or fully compensated.
- The California Energy Crisis of 2001, in which anticompetitive behavior in the poorly designed, newly-formed competitive wholesale market, combined with strict constraints on hedging imposed on the utilities, caused runaway spikes in power prices, leading to financial disaster for utilities.

A more recent and less dramatic, but still widespread, example of asymmetric risk is the regulatory disallowances of utility gas hedging costs in forward contracts that were struck when natural gas wellhead prices were high (2007–2009). These positions became rapidly and significantly "out of the money" as gas prices fell dramatically due to technological advances in shale gas development. There was no reward (in most cases) for utilities whose hedges ended up being in the money, but penalties and disallowances for those whose hedges turned out to be above spot prices in the delivery months. Hence, a one-sided, "heads I break even, tails I lose" proposition.

In order for investors to be comfortable with funding an entity facing substantial asymmetric risk, stipulated or "promised" returns must exceed the cost of capital. Again, the example of corporate bonds helps to show why this is the case. The best a bondholder can hope for is that the bond pays off in full and on time at its promised coupon rate of return. However, the bond might instead default, in which case the bondholder will receive something less than the promised coupon return. The expected return, the probability-weighted average of returns in scenarios ranging from the best (*i.e.*, no default) to the worst (*i.e.*, receipt of less than the promised payments) outcomes, will be below the promised return, and equal to the actual cost of capital. This means the yield on a junk bond is not its cost of capital, but the amount it needs to potentially collect to earn its somewhat lower cost of capital, illustrated in Figure 11 below.

Figure 11: Illustration of Risk and Return Scenarios



To remedy the possibility of loss relative to the promised payments, investors will bid bond prices down to a level where the yield to maturity compensates for the perceived likelihood of downside outcomes; that is, to where the prevailing yield, times 1 minus the probability of default, equals the true cost of capital. This is why bonds with poorer ratings have progressively higher yields compared to U.S. Treasury bonds of comparable maturity.

Notably, while investment in regulated utilities resembles investment in corporate bonds from the perspective of facing asymmetric risk (in that many investors turn to utilities for relatively steady, likely cash flows), utility investments differ in that it is not clear they are similarly compensated for "default" (asymmetric) type risks in their allowed levels of return. This is because regulators have traditionally adopted the academic definition of cost of capital—on which allowed returns are based—as equal to expected returns. This is a correct understanding of the cost of capital, but if it is awarded as if there is no chance of an asymmetric loss (*i.e.*, as if the factors of future costs and loads used in setting rates are the expected values), the actual expected return for the utility will be below the cost of capital.

Correspondingly, the financial economic models used to estimate the cost of capital reflect the expected outcome, not some analogue to the "promised" outcome. The Capital Asset Pricing Model ("CAPM"), for example, commonly relies on historical data to estimate betas and the market risk premium, and those historical data include bad outcomes as well as good ones. Similarly, the Discounted Cash Flow model ("DCF") uses forecasts of dividend or earnings' growth rates. Properly developed, those forecasts should take the possibility of bad, asymmetric outcomes into account, but so does the stock price against which the Internal Rate of Return ("IRR") of the projected cash flows is determined, so again there is no net revelation of the cost of these downsides. In neither case can we observe what the return would be that is equivalent to a corporate bond's "in full and on time" outcome and then adjust it to being a default-weighted yield. Thus, an allowed rate of return equal to the cost of capital does not provide an adequate rate of return for a regulated company faced with substantial loss from asymmetric risk, even when the cost of capital is estimated perfectly and the market is fully aware of the risks facing the regulated company.[103]

This result might seem paradoxical, because the cost of capital is also deemed by financial economists to be the required return for the underlying risks. Stock prices in an efficient market should rise or fall to a level where the expected return is also the required return. However, not all risks require a return, if they can be diversified away. This is often the case for asymmetric risks, to the extent they arise for idiosyncratic reasons unrelated to financial markets or the economy as a whole but instead are peculiar to the luck and specific circumstances of the company in question. At the extreme, consider a utility whose disallowance risk, or failed cost recovery risk from unforeseen market or regulatory conditions, is equivalent to flipping a coin and getting tails instead of heads. Such random risks have nothing to do with the economy, so they are deemed "nonsystematic" and are generally diversifiable (if held in a portfolio of many other securities in the market, some of which might benefit from the same problem).

This is not to say that such risks do not matter to investors or to the management of the affected companies. To the contrary, those asymmetric exposures reduce expected future cash flows and so reduce the value of the stock, but once that is reflected in the price, there is no additional premium for the problem. As an analogy, you could not expect to earn more on a home you bought in a region with hurricane risks than one in a region without that problem. Instead, the home in the hurricane region should sell for less, everything else being equal, and then appreciate comparably to elsewhere. To offset the hurricane risk, you need insurance, not a higher appreciation rate for the house.

Importantly, asymmetric risk cannot be ignored by regulators simply because it is not priced by traditional models, such as the CAPM or DCF models used to estimate the cost of capital. Under long-received and uncontroversial legal decisions and regulatory conventions, utilities must be entitled to a fair (*i.e.*, unbiased) opportunity to earn their cost of capital against their prudently invested capital. This assures they will be cost-based and adequately compensated compared to unregulated investments of similar risk. (Recall that unregulated investors can pick and choose their targets to achieve their expected return, while utility managers and their investors cannot.) Thus, if regulatory allowances for revenue requirements and the associated return components are not somehow marked up to offset the black swan possibility of adverse events asymmetrically

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103 There is an exception to this general rule, whereby some of the cost of the asymmetric risk may be priced. It is likely that as a political matter, most regulators are more willing and able to extend a cost recovery allowance for unexpected costs if the economy is doing well, while they may be very reluctant to do so if the economy is doing poorly. If so, there will be some portion of asymmetric losses that is more likely to be recoverable in proportion to the state of the economy. This will make them somewhat systematic, and over time that premium should be observed in the CAPM (once the period of history for the sampling includes such events and firms with comparable exposure). However, the state of the economy is certainly not enough to assure recovery in good times and nothing in poor ones, and even if that was the case, there would be net losses. So some, likely most, asymmetric risk is never priced in the measured cost of capital.

undermining cost recovery, this goal of risk parity with other financial investments will not be achieved. For utilities, the "promised return" is just the allowed cost of capital, which, unlike the bond yield, does not include a markup for default risk.

It is equally true that asymmetric risk is not compensated in the cost of capital of unregulated firms, yet they seem to get by without any requests or needs for supplemental compensation. Why then do utilities need an allowance? The answer is their obligation to serve. The utilities must invest whenever there is a need and then hope to get back their cost of capital. In contrast, unregulated firms can wait to invest until the need is so strong that they can expect to earn more than their cost of capital if no black-swan types of asymmetric events occur. Unregulated firms can also retain excess profits indefinitely when they are not incurring unlucky outcomes, while utilities are not usually eligible for such excess profits.

In principle, you could solve this by assessing the asymmetric downside exposure and adding to the allowed ROE (above the measured cost) to make a utility revenue allowance more like a bond yield, probabilistically scaled up for "default" risk. However, it is generally not appropriate to do this for utilities because by providing compensation for an asymmetric risk that is within the control of the regulator to impose, the regulator may be tempted to later impose the loss on the utility, reasoning that the utility had already received compensation for the expected risk. The latter will necessarily be below the true cost of the risk, once fulfilled, if the ROE risk adjustment gives the regulator license to penalize. Under these moral hazard conditions, adequate compensation for the risk of disallowance would have to be equal to the full amount of the investment that could be disallowed.

Appendix B: Sources to Figure 2 and Figure 3

Sources to Figure 2

Label	Value	Source
2003 Western Wildfires	$3.9B	"U.S. Billion-Dollar Weather and Climate Disasters 1980–2018," NOAA National Centers for Environmental Information (NCEI), accessed February 2019, https://www.ncdc.noaa.gov/billions/events/US/1980-2018. Hereafter referred to as "NOAA Table." Smith, Adam B., and Jessica L. Matthews, "Quantifying Uncertainty and Variable Sensitivity within the U.S. Billion-dollar Weather and Climate Disaster Cost Estimates," accessed February 2019, https://www.ncdc.noaa.gov/monitoring-content/billions/docs/smith-and-matthews-2015.pdf.
Hurricane Katrina	$125B	NOAA Table.
2007 Western Wildfires	$2.7B	NOAA Table.
Southeast Tornadoes	$10.2B	NOAA Table, 2011 Southeast/Ohio Valley/Midwest Tornadoes.
Las Conchas Fire	$614.5MM *(economic damage)*	Impact DataSource, "The Full Cost of New Mexico Wildfires," January 24, 2013, page 4, accessed February 2019, https://pearce.house.gov/sites/pearce.house.gov/files/6%20Full_Cost_of_New_Mexico_Wild_Fires_1-24-13.pdf.
Hurricane Irene	$13.5B	NOAA Table.
Bastrop County Complex Fire	$600MM *(economic damage)*	Aon Benfield, "Costliest U.S. Wildfires: Economic Loss (1950-Present)," accessed February 2019, http://catastropheinsight.aonbenfield.com/Top10/U.S.-Wildfire-Economic-Insured-Loss-Events.pdf.

Nor'easter Snowstorm – All States	$3B *(economic damage)*	Aon Benfield, "October 2011 Monthly Cat Recap – Impact Forecasting," November 3, 2011, accessed February 2019, http://thoughtleadership.aonbenfield.com/ThoughtLeadership/Documents/201111_if_monthly_cat_recap_october.pdf.
Midwest/Mid-Atlantic Derecho	$2.9B	NOAA Table, 2012 Plains/East/Northeast Severe Weather.
Waldo Canyon Fire	$453.7MM *(insured loss)*	"Wildfire," Rocky Mountain Insurance Information Association, accessed February 2019, http://www.rmiia.org/catastrophes_and_statistics/Wildfire.asp.
Hurricane Sandy	$65B	NOAA Table.
Polar Vortex	$2.2B	NOAA Table, 2014 Midwest/Southeast/Northeast Winter Storm.
Napa Earthquake	$1B *(economic and damage losses)*	Maya Rhodan, "Damage from California Earthquake Could Top $1 Billion", *Time*, August 25, 2014, accessed February 2019, http://time.com/3173406/california-napa-earthquake-damage/.
Butte & Valley Fires	$2B *(economic damage)*	Aon Benfield, "2015 Annual Global Climate and Catastrophe Report," January 13, 2016, page 23, accessed February 2019, https://www.aon.com/global-weather-catastrophe-natural-disasters-costs-climate-change-annual report/index.html.
Hurricane Harvey	$125B	NOAA Table.
Hurricane Irma	$50B	NOAA Table.
2017 Western Wildfires	$18B	NOAA Table, 2017 Western Wildfires, California Firestorm.
Tubbs Fire	$8.7B *(insured loss)*	Aon Benfield, "2018 Weather, Climate & Catastrophe Insight," January 22, 2019, page 72, accessed February 2019, https://www.aon.com/global-weather-catastrophe-natural-disasters-costs-climate-change-annual report/index.html. Hereafter referred to as "Aon Benfield 2018."

Hurricane Maria	$90B	NOAA Table.
Carr Fire	$1.8B *(economic damage)*	Aon Benfield 2018, Appendix A.
Woolsey Fire	$5.75B *(economic damage)*	Aon Benfield 2018, Appendix A.
Camp Fire	$15B *(economic damage)*	Aon Benfield 2018, Appendix A.
Mendocino Complex Fire	$350MM *(economic damage)*	Aon Benfield 2018, Appendix A.
Thomas Fire	$2.2B *(insured loss)*	Aon Benfield 2018, page 72.
Volcano Eruptions in Hawaii	$500MM *(economic damage)*	Aon Benfield 2018, Appendix A.
Hurricane Florence	$15B *(economic damage)*	Aon Benfield 2018, Appendix A.
Hurricane Michael	$17B *(economic damage)*	Aon Benfield 2018, Appendix A.

Sources to Figure 3

Label	Value	Source
2018 Woolsey	TBD	
	96,949 acres	"Woolsey Fire Incident Information," California Department of Forestry and Fire Protection, last modified January 4, 2019, accessed February 2019, http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=2282.
2018 Camp	$10.5B+	Pacific Gas and Electric Company, Form 10-K for the Fiscal Year Ended December 31, 2018, pages 144 and 149–150, accessed

		February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx.
	153,336 acres	"Camp Fire Incident Information," California Department of Forestry and Fire Protection, last modified January 4, 2019, accessed February 2019, http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=2277.
2017 October Northern CA	$10B–$17.3B est.	$10B: Pacific Gas and Electric Company, Form 10-K for the Fiscal Year Ended December 31, 2017, page 28, accessed February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx. $15B: "Fitch Downgrades PG&E Corp. to 'BBB+'; Places on Rating Watch Negative," Fitch Ratings, February 26, 2018, Accessed February 2019, https://www.fitchratings.com/site/pr/10021816. $13.5B–$17.3B: "PG&E Corp. Company Liability Estimates Tell Us Little at This Stage," J.P. Morgan, June 21, 2018, page 2, accessed February 2019.
	179,336 acres	(Tubbs, Nuns, Atlas, and Redwood Valley only) California Department of Forestry and Fire Protection, "Top 20 Most Destructive California Wildfires," last modified March 14 2019, accessed March 2019, http://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Destruction.pdf.
2017 December Southern CA	$4B est.	"Fitch Maintains Southern California Edison & Edison International on Rating Watch Negative," Fitch Ratings, August 23, 2018, accessed February 2019, https://www.fitchratings.com/site/pr/10042429.
	281,893 acres	(Thomas Fire only) "Thomas Fire Incident Information," California Department of Forestry and Fire Protection, last modified March 14, 2019, accessed March 2019, http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=1922.

2015 Butte	$1.1B+ est.	Pacific Gas and Electric Company, Form 10-K for the Fiscal Year Ended December 31, 2018, pages 34 and 156, accessed February 2019, http://investor.pgecorp.com/financials/sec-filings/default.aspx.
	70,868 acres	"Butte Fire Incident Information," California Department of Forestry and Fire Protection, last modified October 15, 2015, accessed February 2019, http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=1221.
2015 Valley	N/A	
	76,067 acres	"Valley Fire Incident Information," California Department of Forestry and Fire Protection, last modified October 15, 2015, accessed February 2019, http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=1226.
2007 Southern CA	$2.4B	California Public Utilities Commission, *Decision Denying Application*, Application No. 15-09-010 (Filed September 25, 2015), Decision 17-11-033, November 30, 2017, page 3.
	516,465 acres	California Department of Forestry and Fire Protection, "California Fire Siege 2007: An Overview," n.d, page 67, accessed February 2019, http://www.fire.ca.gov/fire_protection/downloads/siege/2007/Overview_CompleteFinal.pdf.
2003 Southern CA	$71MM	California Public Utilities Commission, *Opinion on the Reasonableness of San Diego Gas and Electric Company's Response to the 2003 Wildfires*, Application No. 04-06-035 (Filed June 28, 2004), Decision 05-08-037, August 25, 2005, page 3.
	750,043 acres	California Department of Forestry and Fire Protection, "California Fire Siege 2003: The Story," n.d, page 4, accessed February 2019, http://www.fire.ca.gov/downloads/2003FireStoryInternet.pdf.

BOSTON
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THE Brattle GROUP

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

PREPARED DIRECT TESTIMONY OF DR. BENTE VILLADSEN

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-25)

APRIL 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
DR. BENTE VILLADSEN

(EXHIBIT SCE-25)

Dr. Villadsen's testimony supports SCE's proposed conventional return of equity ("ROE"). She applies an analysis based upon a multiple-model methodology that is consistent with the Commission's most recent guidance and policy objectives, with certain refinements, and recommends an ROE of 11.12%. This conventional ROE does not reflect the extraordinary wildfire risk faced by SCE. Dr. Villadsen also discusses SCE's participation in the CAISO and concludes that SCE should receive a Commission-approved adder for SCE's membership in the California Independent System Operator Corporation ("CAISO") of 0.50 percent. Further, Dr. Villadsen explains that several SCE transmission projects have Commission-approved project-specific adders, which are added to the proposed ROE.

Dr. Villadsen's testimony also supports an alternative proxy group consisting of capital-intensive network industries. She concludes that this proxy group of higher risk companies can be applied when considering the unique wildfire risks that SCE faces.

PREPARED DIRECT TESTIMONY OF
DR. BENTE VILLADSEN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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PREPARED DIRECT TESTIMONY OF
DR. BENTE VILLADSEN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Bente Villadsen. I am a Principal at The Brattle Group's ("Brattle") Boston office located at One Beacon St., Suite 2600, Boston, MA 02108, USA.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of Southern California Edison Company ("SCE").

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring this Prepared Direct Testimony, Exhibit No. SCE-25, as well as Exhibit No. SCE-26, which contains my résumé, Exhibit No. SCE-27, which contains the tables supporting Tables 1-5 of this testimony and Exhibit No. SCE-28, which describes the methodology used for additional analyses and supports Tables 7-10.

Q. PLEASE DESCRIBE YOUR CURRENT POSITION AND RESPONSIBILITIES AT BRATTLE.

A. I am a Principal of *The Brattle Group*, an economic, environmental, and management consulting firm with offices in Boston, Washington D.C., London, San Francisco, Madrid, Rome, New York, Toronto, Sydney, and Brussels with specialties including financial economics, regulatory economics, and the gas, water, and electric industries. My work concentrates on regulatory finance and accounting. As a Principal, I work in the areas of cost of capital, risk, regulatory accounting, regulatory precedence and related matters for regulated entities, regulators, or investors.

I am the co-author of the text, "Risk and Return for Regulated Industries" and I have testified or filed expert reports on cost of capital in Alaska, Arizona, California, Illinois, New Mexico, New York, Oregon, and Washington, as well as before the Bonneville Power Administration, the Surface Transportation Board, the Alberta Utilities Commission, and the Ontario Energy Board. I have provided white papers on cost of capital to the British Columbia Utilities Commission, the Canadian Transportation Agency as well as to European and Australian regulators on cost of capital. I have testified or filed testimony on regulatory accounting issues before the Federal Energy Regulatory Commission ("Commission"), the Regulatory Commission of Alaska, the Michigan Public Service Commission, the Texas Public Utility Commission as well as in international and U.S. arbitrations and regularly provide advice to utilities on regulatory matters.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. I have testified on regulatory accounting matters before the Commission in dockets PA10-13-000 and EL11-13-000.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Ph.D. from Yale University's School of Management with a concentration in accounting. I also hold a MS as well as a BS joint degree in mathematics and economics from University of Aarhus in Denmark.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to determine the return on equity for SCE. I do so by determining the reasonable range for a proxy of electric utilities using the revised FERC methodology specified in the NETO Briefing Order.[1] Having determined the reasonable range, I place SCE within the range taking into account the Company's higher than average risk. Importantly, my point estimate for SCE does **not** include consideration of SCE's wildfire related risks. Finally, I demonstrate that the zone of reasonableness is too constrained for a company such as SCE. Specifically, the application of the Commission's methodology to a sample of capital-intensive network industries provides a wider zone of reasonableness and thus demonstrates that there are plenty of network industries that have wider range of ROE results that what a traditional Commission sample selection method would give rise to.

III. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Based on my calculations of the ROEs for the proxy group, I recommend that SCE be placed at the upper midpoint of the reasonable range for a ROE of 11.12% before the addition of incentives or other requested adders. The recommendation is based

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[1] Coakley v. Bangor Hydro-Elec. Co., Opinion No. 531, 147 FERC ¶ 61,234 (2014), order on paper hearing, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), order on reh'g, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), vacated & remanded sub nom. Emera Maine, 854 F.3d 9, order on remand, Coakley v. Bangor Hydro-Elec. Co., 165 FERC ¶ 61,030 (2018) ("NETO Briefing Order").

on the determination of the CAPM, DCF, and expected earnings ROE for a sample of 33 electric utilities. I also report the results from the risk premium model.

I recommend that the ROE for SCE, before incentive or other adders be placed at the midpoint of the upper part of the Zone of Reasonableness ("ZOR")[2] because SCE is of higher risk than the average electric utility. I recognize that the NETO Briefing Order stated that it would use the upper median for a single filer and the upper midpoint for a group-filer. However, from a financial economics perspective the cost of equity depends on the use of assets not the ownership of such assets.[3] Consequently, it is the risk of the underlying assets and not the characteristics of the owner of such assets that determine the appropriate return on equity. Therefore, there is no financial theory that justifies treating a single-filer different from a group-filer. I also did not find a discussion of the economic justification for this difference in treatment in light of the new methodology in the NETO Briefing Order.

Additionally, I find that an alternative sample consisting of Capital-Intensive Network Industries has a much wider range of ROE estimates using the FERC's methodology.[4] The range of ROE estimates from this sample demonstrates that for higher risk companies, the FERC methodology gives rise to a wider ZOR when implementing the FERC methodology. The use of such a sample to assess the plausible ZOR for non-standard adders is merited because SCE faces unique

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[2] For clarity, the ZOR is determined as the range of estimates that encompasses the lowest estimate that is at least 100 basis points above the yield on BBB rated debt and no higher than the lesser of the highest ROE estimate and 1.5 times the median estimate.

[3] See, for example, Brealey, Myers & Allen, "Principles of Corporate Finance," 11th Edition, 2014, p. 219.

[4] Using FERC's methodology (including outlier tests), the alternative sample has a range of approximately 6.3% to 18.1%.

circumstances in the form of wildfire risks. Specifically, wildfires carry downside risks only and represent an asymmetric risk, which is the result of an investment having the potential to experience a large negative return without any possibility of an offsetting positive return. The asymmetric risk resulting from California legislation and wildfires is discussed in the testimony of Mr. Frank Graves.[5] This risk is unique and not captured in my Electric Utility Sample.[6] Consequently, I develop an alternative sample of Capital-Intensive Network Industries to assess what ROE would result if a broader set of companies were considered.[7]

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Section IV formally defines the cost of capital, and touches on the principles relating to the estimation of the cost of capital for a business and the theory underlying the discounted cash flow model. Section V first describes the criteria used to create the FERC Electric Utility Sample and provides a summary of the sample. It then describes the Commission's revised cost of capital estimation method and provides the results of the revised FERC ROE methodology for the sample. Section VI summarizes my conclusions.

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[5] Prepared Direct Testimony of Mr. Frank Graves.

[6] While other electric utilities in California may face the same type of asymmetric risk, Pacific Gas & Electric is currently in Chapter 11, which leaves only Sempra Energy as a California based utility in the sample.

[7] For clarity, my testimony does not address what liability may be imposed on SCE nor does it address what return investors may require for accepting that specific risk. It simply recognizes that such risks are **not** captured in the standard electric sample and consequently considers group of capital-intensive network industry companies that may be more comparable albeit none of them are likely to capture the full extent of this liability. I understand that the specifics of the wildfire risk and the appropriate treatment of such risks is discussed in the testimonies of Dr. Gary Stern [Exhibit No. SCE-21] and Mr. Frank Graves [Exhibit No. SCE-22 and SCE-24].

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

IV. COST OF CAPITAL THEORY

A. The Cost of Capital and Risk

Q. PLEASE FORMALLY DEFINE THE TERM "COST OF CAPITAL."

A. The cost of capital can be defined as *the expected rate of return in capital markets on alternative investments of equivalent risk*. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected" in my testimony, as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes. The definition of the cost of capital recognizes a tradeoff between risk and return that is known as the "security market risk-return line," or "security market line" for short. This line is depicted in Figure 1. The higher the risk, the higher the cost of capital. Variations of Figure 1 apply for all investments.

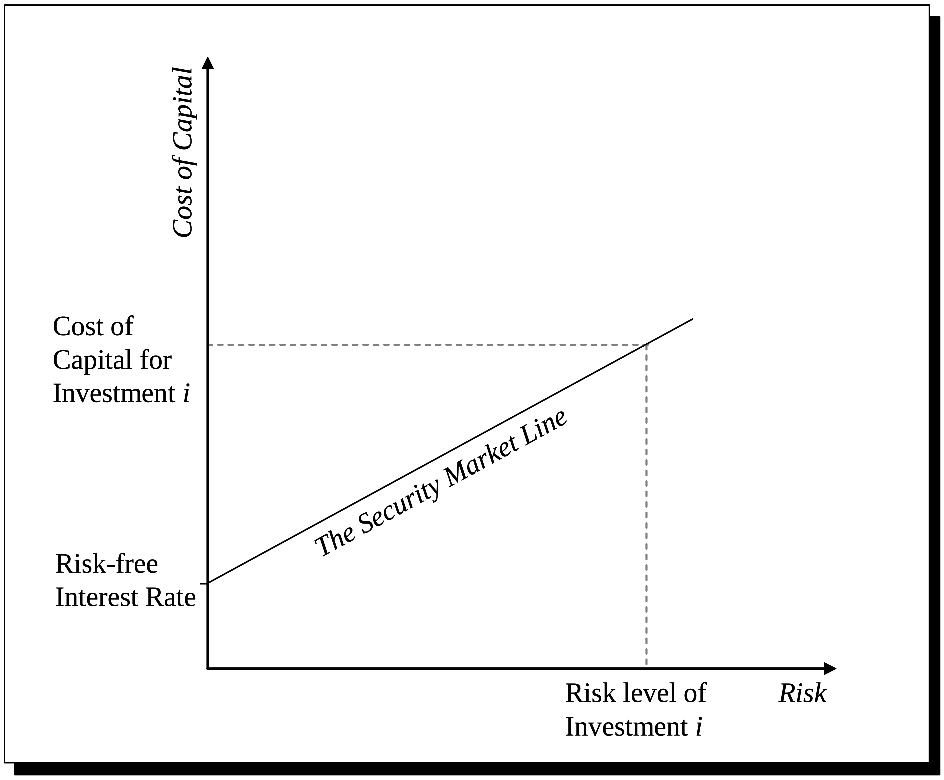

Figure 1: The Security Market Line

Q. PLEASE EXPLAIN WHY THE COST OF CAPITAL IS RELEVANT IN RATE REGULATION?

A. It has become routine in U.S. rate regulation to accept the "cost of capital" as the appropriate expected rate of return on utility investment. That practice is normally viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

A return that determines the ROE (absent incentive or other adders) as the expected rate of return investors require will maintain SCE's ability to attract capital and maintain its financial integrity.

Importantly, an inadequate return raises serious issues not only for the regulated utility but also for its customers. Specifically, it may adversely affect the utility's ability to provide stable and favorable rates because the Company may need to potentially postpone desirable projects that are not needed for reliable service in the near term or it may require the Company to file more frequent rate cases. Long term, inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. The costs of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the cost of capital. Moreover, in capital-intensive industries (such as the electric utility industry), systems with long expected service lives cannot be fixed overnight.

V. SCE'S RISK PROFILE

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. This section first outlines the unique risks that SCE is facing. Specifically, I (i) briefly discuss the unique risks that merit placing SCE at the upper midpoint of the reasonable range that results from implementing the Commission's ROE methodology and (ii) describe additional risks from wildfires that merits an alternative zone of reasonableness for SCE's all-in ROE.

Q. WHAT ARE THE UNIQUE RISK FACTORS THAT SCE FACES?

A. SCE is located in California, which has many regulatory and legislative risks that are not common to other electric utilities. California has embarked on major electricity related transformations on more than one occasion. These changes to the status quo disrupt the electric utility business and have a proven track record of enhancing risk to the utilities.[8] The Commission should consider these unique risks in setting SCE's ROE to ensure consistency with the criteria outlined in *Hope* and *Bluefield*, including that the ROE must be comparable to returns on *investments of similar risk*.

The direct testimony of Dr. Gary Stern discusses several of the California specific risks that SCE faces. These include: (1) unique risks SCE faces due to California environmental and other policies; (2) risks relating to SCE's role in procurement; (3) risks relating to California's approach to retail electric competition and associated load uncertainty; (4) risks relating to regulatory lag in California; and (5) risks relating specifically to SCE's transmission assets.

Q. WHAT IS THE MOST SEVERE RISK THAT SCE FACES?

A. Wildfire liabilities are currently the most immediate and catastrophic risk for SCE and in recent years, wildfires have become a year-round phenomenon with increasing severity.[9] The intensity of California wildfires has increased over time, as two-thirds of the state's largest fires on record have occurred in the last 20 years.[10] In California, the legal doctrine of inverse condemnation means that SCE faces strict liability for damages resulting from fires that the courts find were caused by SCE's utility equipment. SCE has significant cost-recovery uncertainty for those

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[8] Such policies are currently implemented primarily for environmental reasons.

[9] See, for example, http://calfire.ca.gov/communications/downloads/newsreleases/2018/WAWNewsRelease_2018_FINAL.pdf, downloaded, information accessed February 15, 2019 ("Already this year [May 7, 2018] CAL FIRE has responded to more than 950 wildfires that have burned over 5,800 acres. We need Californians to accept fire as part of our natural landscape, understand the potential fire risk. CAL FIRE's 'Ready for Wildfire' app is the perfect tool to use in year-round preparation.").

[10] http://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Acres.pdf, downloaded, information accessed August 23, 2018

damages due to a recent decision by the California Public Utilities Commission ("CPUC").[11]

The liability and financial implications of the Courts' application of inverse condemnation combined with the CPUC's recent decision, is unique to California utilities. The presence of large and unique risks is the reason I consider an alternative to assess a range of reasonable returns investors may seek to carry the unique risks in California. This alternative sample consists of capital-intensive companies that operate in network industries. This means that they, like SCE, rely on a buildout system of assets. While these companies generally do not face the same magnitude of potential and imminent liabilities, as does SCE, they have a larger risk exposure than traditional electric utilities and therefore are an appropriate alternative consideration for the purpose of determining the return that investors in SCE may be seeking once all risks are considered.

Q. ARE WILDFIRE RISKS INCLUDED IN YOUR ROE ESTIMATE?

A. No. The risks associated with the California wildfires are (i) generally not present among the electric utilities in my proxy group[12] and (ii) most commonly represent an asymmetric risk, so that SCE faces a potential liability or cost from the wildfires, but there is no offsetting upward return opportunity. Such asymmetric risks are not included in the ROE that I estimate using common cost of equity models.[13] As a

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[11] CPUC Decision (D.)17-11-033, *Decision Denying Application* (issued December 6, 2017); reh'g denied, D.18-07-025 *Order Denying Rehearing of D.17-11-033* (July 12, 2018).

[12] Sempra is included in my proxy group but (1) is one of 33 companies and (2) does not determine either the lower or the upper end of the Zone of Reasonableness.

[13] A detailed discussion of asymmetric risk is provided in Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, "*Risk and Return for Regulated Industries*," Academic Press, 2017, Chapter 10. See also Leonardo R. Giacchino and Jonathan A. Lesser, "*Principles of Utility Corporate Finance*," Public Utilities Reports, Inc., 2011, pp. 25-26.

result the return that investors require to bear such risks has to be considered separately (e.g., outside my ROE estimate, which relies on a sample of electric utilities without such risks) and I understand that the testimony of Mr. Frank Graves does so.

Q. WHAT OTHER RISKS ARE UNIQUE TO SCE, IF ANY?

A. California is a leader in addressing climate change and air pollution, with the legislature and the CPUC spearheading an industry transformation towards a clean energy future. These disruptions in the status quo, while certainly providing environmental and other public benefits, enhance risk to the California utilities, including SCE. Dr. Stern discusses these risks in detail in his testimony, at Exhibit SCE-21. As Dr. Stern states, SCE is committed to this clean energy future, through use of renewable energy, energy storage, energy efficiency programs, and using a cleaner grid to improve the transportation sector and building performance through electrification. SCE and other California utilities play an important role in implementing California's environmental goals, but it comes with substantial risk to the utility. The state's aggressive environmental policy objectives, and continual changes in such policies, leaves SCE with a substantial level of planning and cost recovery risks associated with designing and operating a grid that can safely and reliably support these objectives. Such risks include changing rules for retail customer competition relating to Community Choice Aggregation ("CCA") and Direct Access and associated uncertainty as to the amount of load SCE will be responsible to procure energy to serve. This, coupled with the significant and growing amount of Distributed Energy Resources ("DER"), creates more uncertainty for SCE. SCE performs significant power procurement activities, including energy, capacity and natural gas procurement, and maintains SCE's role as provider of last resort. For example, according to SCE estimates, Dr. Stern notes that portions of their existing renewable portfolio is about $12B above market. In addition, Dr. Stern notes the adoption of new and unproven technology, such as storage, and the need to build and operate a modern grid to accommodate DERs (*e.g.*, support two-way power flows). While these initiatives are not unique to California, the magnitude is. As a result, the impact of new roles for electric service providers, DER, new technology and other mandates, combined with the pace of the changes in such mandates, technologies and prices, creates large risks for SCE and significant impacts on its system and transmission planning.

Q. PLEASE SUMMARIZE THE IMPACT OF CALIFORNIA'S CARBON REDUCING GOALS ON SCE'S BUSINESS.

A. As noted above, California has one of the most aggressive Renewables Portfolio Standards ("RPSs") in the nation. [14] For example, SB 100 set a goal of 100 percent clean electricity by 2045, and 60 percent renewables by 2030, while the 2015 goal through Senate Bill 350 was 50 percent from renewables by 2020. Earlier versions had lower targets (albeit at a closer date). These standards are higher than that of all other states but Hawaii and unlike many other states do not have a legislatively imposed cost cap.[15] Such a moving target requires SCE to address reliability issues and to handle the potential for excess generation capacity going forward.

[14] Megan Cleveland, *States' Renewable Energy Ambitions* (February 4, 2019) available at: http://www.ncsl.org/research/energy/states-renewable-energy-ambitions.aspx

[15] http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx as assessed on March 20, 2019. I understand that the CPUC may impose a cap.

Additionally, the changing targets poses uncertainty for SCE's planning process. This adds to SCE's risk not only for generation but also for transmission, which is needed to move the renewable energy to end-users.

Q. ARE THERE OTHER UNIQUE RISKS FACING SCE?

A. Yes. There is a renewed policy shift towards deregulation and electric competition in California, as reflected by California's now expanding Direct Access program, its CCA, and the growth of DERs. This creates business and regulatory risks for SCE that further amplify the risks relating to changes in its grid design and operation. The president of the CPUC recently acknowledged these substantial risks

> we are deregulating electric markets through dozens of different decisions and legislative actions, but we do not have a plan. If we are not careful, we can drift into another crisis.[16]

Q. HOW DO THESE PROGRAMS CREATE RISK FOR SCE?

A. California's Direct Access program allows a limited selection of consumers in California to purchase their electricity from an Electric Service Provider ("ESP"), instead of their utility. This means that SCE faces declining demand that is outside its control – yet SCE has to plan for the ability to serve all customers.

Similarly, the California utilities are seeing a number of customers dropping off its load to be served by CCAs. CCA permits customer groups, including cities or counties, acting alone or in purchasing groups, to procure electricity directly from

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[16] California Customer Choice, An Evaluation of Regulatory Framework Options for an Evolving Electricity Market (August 2018), at iii, *available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf* (last accessed March 25, 2019).

wholesale non-utility suppliers. The utility continues to provide distribution services, billing, and metering. Much like the Direct Access programs, the potential for CCA affects SCE's ability to predict the size of its customer base and the load for which it must procure or generate electricity, adding to the risks of committing to longer-term resources. Dr. Stern notes that, as of December 31, 2017, SCE reported contractual obligations for power purchase agreements of almost $40 billion.[17] SCE has also done significant procurement of renewable energy. Because of declining prices and improvements in technology, much of its current contract holdings are above market. As noted, SCE estimates its existing renewable portfolio is $12B above market through 2035.[18] In the presence of CCA and departing load, it becomes increasingly unclear what customers will remain and thus be responsible for the renewable portfolio, and other contracts, which are now above market costs. The CPUC is currently examining this in an open proceeding.[19] Dr. Stern discusses this issue in more detail in his testimony, Exhibit SCE-21.

Specifically, the CPUC in October 2018 adopted a revised version of its Power Charge Indifference Adjustment ("CPIA"), which is "the mechanism to ensure that the customers who remain with the utility do not end up taking on the long-term financial obligations the utility incurred on behalf of now-departed customers," such as utility expenditures to build power plants and long-term power purchase agreements.[20] The CPUC recently adopted a revised PCIA methodology, including an annual true-up mechanism and cap.[21] This decision opens up a second phase of

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[17] Exhibit No. SCE-21, Dr. Stern's Prefiled Direct Testimony, provides the details.
[18] See Exhibit No. SCE-21.
[19] Exhibit No. SCE-21, Dr. Stern's testimony.
[20] *See* http://www.cpuc.ca.gov/PCIA/ (*last visited* March 6, 2019).
[21] CPUC Decision 18-10-019, issued October 19, 2018.

the CPUC's PCIA rulemaking to consider utility portfolio optimization, to establish a process for ESPs (i.e., Direct Access) or CCAs choosing to prepay their PCIA obligation, to develop the true-up process for the market price benchmarks used to calculate the PCIA, and to consider other potential issues related to the PCIA.[22] As Dr. Stern discusses in his testimony, while D.18-10-019 provides some certainty in terms of a revised PCIA methodology that provides a greater likelihood that SCE's bundled service customer will remain indifferent to departing customers, uncertainty remains around how accurate the true-up process will be, what impact the cap will have, and what potential portfolio optimization measures the CPUC will require SCE to implement.

Another factor to consider is the growth in DER, where an increasing number of customers install their own generation capacity. Through policies such as Net Energy Metering ("NEM"), customers who install self-generation technologies avoid transmission and distribution investment costs incurred by SCE on behalf of its customers. Dr. Stern notes SCE has over 2300MW of roof-top based solar within its service territory.[23] Yet, SCE continues to incur transmission (and distribution) costs, so when groups of customers avoid paying for these costs, the fixed portion of the costs are re-allocated to remaining customers. This in turn leads more customers to become self-generating and SCE's ability to recover its costs becomes more and more challenging.

[22] CPUC Decision 18-10-019 at pp. 111-119, Ordering Paragraph No. 14.
[23] Exhibit No. SCE-21, Testimony of Dr. Stern.

Q. HOW DOES THE CHANGING POLICY AND THE PACE OF THE CHANGES AFFECT THE RISKS OF SCE'S INVESTORS?

A. As energy policy changes, the scope and design of the transmission assets change and consequently, some assets that were designed and built to meet prior goals may now need to be modified, retired, or otherwise re-purposed. Dr. Stern's testimony cites several examples of the cancellation of transmission projects occurring as a result of changes in demand forecast due to the growth of distributed solar generation. The pace of change regarding both policy and technological development increases the Company's risk exposure. As the goals and the need for specific assets change, SCE's ability to earn its allowed return on equity changes. Specifically, it gets more and more difficult to collect costs associated with abandoned projects or stranded assets.

Q. WHAT ARE THE IMPLICATIONS OF THESE UNIQUE RISKS?

A. These risks mean that SCE is riskier than the electric utility industry and the proxy group I use. Consequently, it is necessary that the Commission grant SCE a return on equity that will ensure comparability to the return on similar risk entities and one that allows SCE to attract capital on reasonable terms and maintain its financial integrity.

Q. HAS SCE IN THE PAST BEEN GRANTED ANY INCENTIVE ADDERS?

A. Yes. As approved by the Commission's Order Granting Petition for Declaratory Order in Docket EL07-62-000[24], SCE is requesting a 0.50 percent adder to the base ROE to compensate SCE for its membership in the CAISO ("CAISO Adder").

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[24] *Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007) at p. 158.

Similarly, in Docket ER 18-169-000 (December 2017), the Commission issued an order accepting SCE's Second Formula Rate subject to refund and granted SCE's request for the CAISO Adder.[25] This CAISO adder was challenged by the CPUC and the Transmission Agency of Northern California and a rehearing request remains pending.[26]

Q. DOES SCE'S REQUEST FOR AN INCENTIVE ADDER FOR CAISO MEMEBERSHIP HAVE MERIT?

A. Yes. SCE's participation in CAISO has resulted in tangible benefits. For example, CAISO, though it's FERC-jurisdictional tariffs, has implemented numerous policies and practices that benefit the CAISO grid and its customers.[27] Significantly, the CAISO has actively been implementing Order 1000, which allows for competitive transmission in the CAISO footprint.[28] Further, the CAISO plans the transmission system to meet reliability standards and resiliency goals and manages market issues. Notably, the July 31, 2018 western Energy Imbalance Markets ("EIM") quarterly report indicates significant benefits flowing to CAISO members regarding cost savings.[29]

Lastly, providing incentive adders for CAISO is consistent with past precedents

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[25] *Southern California Edison Co.*, 161 FERC 61,309 at P 25. A remand order regarding Pacific Gas & Electric ("PG&E") rate cases and the CAISO adder also is pending.
[26] *Order Granting Rehearing for Further Consideration*, Dkt. Nos. ER18-169-001, EL18-44-001 (Feb. 28, 2018).
[27] See Exhibit No. SCE-21, the testimony of Dr. Gary Stern, for details.
[28] See Sections 24.5 and 24.18 of the CAISO's tariffs. Available at http://www.caiso.com/Documents/ConformedTariff-asof-Mar1-2019.pdf
[29] *Western EIM Benefits Report*, Second Quarter 2018, dated July 31, 2018, at p. 4 (indicating $27.93 million of estimated EIM gross benefits attributable to the CAISO in the second quarter of 2018), *available at* https://www.westerneim.com/Documents/ISOEIMBenefitsReportQ2_2018.pdf.

Q. WHAT IS YOUR RECOMMENDATION CONCERING AN ISO INCENTIVE ADDER FOR SCE?

A. SCE has been and continues to be a member of the CAISO. Consistent with Commission policy, while SCE remains within the CAISO it should receive the ISO incentive adder.

Q. HAS THE COMMISSION PREVIOUSLY GRANTED SCE ADDITIONAL ROE INCENTIVES FOR SPECIFIC TRANSMISSION PROJECTS?

A. Yes. The Commission has previously granted ROE incentive adder on three specific transmission projects. These projects and their associated ROE incentive adders are: Rancho Vista, 0.75 percent; Tehachapi, 1.25 percent; and Devers-Colorado River, 1.00 percent.[30] Given my recommended conventional ROE of 11.62% inclusive of the CAISO adder, the total ROEs for these three projects are 12.37 percent, 12.87 percent, and 12.62 percent, respectively. In accordance with past precedents, SCE should continue to receive incentives for these projects. While the Tehachapi project and to a lesser degree the Devers-Colorado River are above the upper end of the Commission's conventional reasonable range, I note that there certainly are companies in the full range with an estimated ROE above 12.87 percent. For example, CMS Energy shows 14.4% based on the Expected Earnings method.

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[30] *See*, *Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007) at P 129 and *Southern California Edison Co*., 132 FERC ¶ 61,213 (2010).

VI. THE COMMISSION'S REVISED COST OF CAPITAL METHODOLOGY

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. This section first outlines the steps involved in selecting the sample companies used in the FERC Electric Utility Sample. Second, it describes the Commission's revised ROE method in general and provides the specifics of the implementation of the models. Third, the section discusses the results of my ROE calculations. Finally, this section concludes with a discussion of current economic conditions in the U.S., including how these conditions have affected the capital markets and impacted cost of capital.

A. Sample Selection

1. Sample Selection Criteria

Q. PLEASE EXPLAIN WHAT CRITERIA YOU APPLIED IN SELECTING A SAMPLE THAT IS CONSISTENT WITH THE COMMISSION'S PRECEDENT FOR TRANSMISSION ENTITIES.

A. I have reviewed key Commission decisions and selected a sample consisting of electric transmission-owning utilities typically used by the Commission (FERC Electric Utility Sample). For the reasons discussed above, I believe that SCE is of higher risk than the FERC Electric Utility Sample before the consideration of any wildfire risks. The magnitude of the potential liabilities associated with wildfire risks combined with California legislation means that these risks are extraordinary and not captured in the FERC Electric Utility Sample. Consequently, I develop an alternative sample of capital-intensive network industries to assess what the potential ROE range for such companies might be.

To develop the FERC Electric Utility Sample, I started with the universe of 41 electric transmission-owning companies in the U.S. as reported by *Value Line*. I then determined, whether each company met the Commission's standard criteria, which means that I checked whether the company (i) is a domestic company with an investment grade credit rating,[31] (b) has issued dividends with no dividend cuts in the last six months, and (iii) has had no substantial completed mergers or acquisitions in the last six months or pending mergers announced in the previous three years (not yet completed). The companies remaining constitute the FERC Electric Utility Sample. Exhibit No. SCE-27, Table BV-2 provides details regarding the selection of the sample, the companies considered for inclusion in the sample, and why some companies were excluded from the final FERC Electric Utility Sample. I note that I did not eliminate a company because it was more than one notch above or below SCE's credit rating for two reasons. First, a restriction based on +/- one credit rating notch would lead to a sample that is too small to capture the electric utility industry. Second, SCE's credit rating has been evolving over the past one to two years and may continue to do so. To illustrate this, Standard & Poor's and Moody's have downgraded SCE (and its parent) three times since January 2018, with Moody's having downgraded both entities 3 notches since the start of 2018. Consequently, the reliance of being within plus or minus one notch for SCE's rating would give differing results depending on the exact timing of the filing. This is exaggerated by the fact that the credit rating agencies have

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[31] Only companies with U.S. traded stock were included in the sample. Therefore, companies with the same parent company appear only once in the sample.

different ratings for SCE and that ratings differ between SCE and its parent EIX.[32] For these reasons, I include all investment grade companies.[33]

Q. WHY DO BOND RATINGS NOT CAPTURE THE RISK THAT EQUITY HOLDERS HAVE IN THE CASE OF SCE?

A. Bond ratings capture the risk to creditors and in the case of very large asymmetric risks such as wildfires, bondholders will, in the case of bankruptcy, get paid before equity holders. Consequently, the potential liabilities associated with wildfire risk are unique and will affect equity holders before bondholders, who have priority in case of bankruptcy. Additionally, there is no sample of U.S. electric utilities that face similar wildfire risks as utilities in California.

2. Characteristics of the FERC Electric Utility Sample

Q. PLEASE DESCRIBE THE FINANCIAL CHARACTERISTICS OF THE FERC ELECTRIC UTILITY SAMPLE.

A. The FERC Electric Utility Sample consists of 33 electric utility companies. provides financial information on the companies in the sample, including each company's last 12 months of revenues as of December 2018,[34] market capitalization as of December 31, 2018, S&P's and Moody's credit ratings, and the Institutional

[32] See, for example, Moody's Investor Service, "Moody's downgrades Southern California Edison to A3 from A2 and Edison International to Baa1from A3; outlooks stable," September 6, 2018; Moody's Investor Service, "Moody's downgrades Edison International to Baa3 and Southern California Edison to Baa2; outlooks negative," March 5, 2019, and Standard & Poor's, "Edison International And Subsidiary Southern California Edison Downgraded to 'BBB': Ratings Placed on Watch Negative," January 21, 2019. For completeness, S&P in a March 18, 2019 update SCE and its parent's ratings and kept the companies on a negative outlook.

[33] *See* Opinion No. 531 at P 52 and P 108, n. 209 ("We note that the credit rating bands are based on only those NETOs that have credit ratings from S&P or Moody's."); *see also Atlantic Grid Operations A LLC, et al.*, Order on Petition for Declaratory Order, 135 FERC ¶ 61,144 at P 88, n. 55 (2011).

[34] December 2018 data reflects the most recent quarterly revenues data available for all companies at the time of the analysis.

Brokers Estimation System (IBES) earnings per share (EPS) forecast for the DCF model. I note that not all models may be implementable for all companies due to data limitations. Further, companies may be excluded from the results if they fail the Commission's outlier tests.

Table 1: Characteristics of the FERC Electric Utility Sample

Company	Last 12 Months of Revenues as of 12/31/18 ($MM)*	Market Cap. As of Most Recent Quarter 12/31/18 ($MM)*	S&P Bond Rating	Moody's Bond Rating	IBES Long Term Growth Rate Forecast	Value Line Projected EPS Growth Rate
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	1,499	3,920	BBB+	WR	N/A	4.53%
Alliant Energy	3,535	10,327	A-	WR	7.25%	4.87%
Amer. Elec. Power	16,196	36,855	A-	Baa1	5.74%	5.09%
Ameren Corp.	6,291	15,919	BBB+	WR	7.70%	4.53%
AVANGRID Inc.	6,478	15,478	BBB+	NA	9.20%	10.25%
CMS Energy Corp.	6,873	14,067	BBB+	Baa1	7.00%	4.66%
Consol. Edison	12,337	24,858	A-	Baa1	2.90%	3.12%
DTE Energy	14,212	20,066	BBB+	Baa1	5.49%	5.95%
Duke Energy	24,521	61,532	A-	Baa1	4.41%	5.74%
Edison Int'l	12,657	18,496	BBB	Baa3	3.75%	6.35%
El Paso Electric	904	2,040	BBB	Baa1	5.10%	4.57%
Entergy Corp.	11,009	15,591	BBB+	Baa2	-3.77%	5.74%
Evergy Inc.	4,276	14,956	A-	Baa2	9.20%	8.78%
Eversource Energy	8,448	20,610	A+	Baa1	5.83%	5.33%
Exelon Corp.	35,986	43,562	BBB+	Baa2	8.77%	10.67%
FirstEnergy Corp.	11,454	19,205	BBB	Baa3	-6.61%	24.35%
Hawaiian Elec.	2,861	3,987	BBB-	WR	7.80%	4.32%
IDACORP Inc.	1,371	4,690	BBB	Baa1	2.60%	3.93%
MGE Energy	560	2,079	AA-	NA	N/A	8.14%
NextEra Energy	16,740	83,076	A-	NA	7.45%	5.58%
NorthWestern Corp.	1,192	2,991	BBB	Baa2	2.59%	2.48%
OGE Energy	2,270	7,828	BBB+	WR	-2.25%	4.46%
Otter Tail Corp.	916	1,969	BBB	WR	N/A	6.83%
Pinnacle West Capital	3,691	9,549	A-	WR	4.16%	6.92%
PNM Resources	1,437	3,273	BBB+	Baa3	4.10%	6.41%
Portland General	1,988	4,092	BBB+	WR	5.05%	3.46%
PPL Corp.	7,785	20,389	A-	NA	3.59%	2.41%
Public Serv. Enterprise	9,696	26,309	BBB+	Baa1	7.21%	5.74%
Sempra Energy	11,687	29,607	BBB+	Baa1	8.69%	9.82%
Southern Co.	23,495	44,541	A-	Baa2	1.68%	4.81%
Unitil Corp.	444	753	BBB+	NA	3.70%	n/a
WEC Energy Group	7,680	21,853	A-	Baa1	4.70%	6.13%
Xcel Energy Inc.	11,537	25,787	A-	A3	6.60%	3.64%

Sources and Notes:
[1] - [4]: Bloomberg as of January 31, 2019. Note that WR means Withdrawn Rating.
Credit ratings checked as of March 25, 2019.
[5]: Long-term (i.e. 5 year) IBES estimates from Thomson Reuters as of January 31, 2019.
[6]: Proj EPS Growth Rate. Value Line Plus Edition as of January 31, 2019
*Revenues and market capitalization data reflect the most recent quarter ending December 31, 2018.

B. FERC REVISED ROE ESTIMATION METHODOLOGY

Q. PLEASE DESCRIBE THE FERC'S REVISED ROE ESTIMATION METHODOLOGY.

A. On October 16, 2018, the Commission issued an Order Directing Briefs ("NETO Briefing Order") on the return on equity ROE to be used by New England electric utilities for setting transmission rates. The Commission proposes to expand the methodological basis for determining the Zone of Reasonableness to encompass three analyses, each applied to the same proxy group of electric utilities:

1. Capital Asset Pricing Model (CAPM)
2. Two-step DCF – same as employed in Opinion No. 531, and
3. Expected Earnings Method.

After excluding low- and high-end outliers from each model's results, the methodology establishes a "composite ZOR." The NETO Briefing Order indicates that outliers are identified based on a minimum spread of 100 basis points ("bps") between the ROE estimate and the yield on BBB-rated utility debt ("low-end") and based on a maximum of a 1.5 multiple of the median estimate ("high-end"). A "Presumptively Just and Reasonable" range of ROEs for the Average Risk Utility is established consisting of one quarter of the composite ZOR, centered around the sample midpoint ROE estimate.[35]

[35] The NETO Briefing Order distinguishes between single filers and group filers unlike Order 531 with single filers ROE focused on the median and group filers focused on the midpoint of the upper half. For reasons discussed below, I focus on the upper midpoint.

For setting the new ROE (i.e., if an existing ROE is determined to be no longer just and reasonable), the methodology uses the average of the midpoints or the medians of the three models along with a *single point estimate* from a proposed fourth methodology, the Risk Premium.[36]

Additionally, the NETO Briefing Order returns the focus to the midpoint/median (for average risk utilities), from the "upper midpoint" established by Opinion 531 albeit the order explicitly notes that the Commission:

> would use the midpoint/medians of the resulting lower and upper halves of the zone of reasonableness to determine ROEs for below or above average risk utilities, respectively.[37]

Consequently, an above-average risk entity such as SCE should be placed in the upper half of the zone of reasonableness.

1. The Capital Asset Pricing Model

Q. CAN YOU EXPLAIN THE CAPM?

A. Yes. Modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a market risk premium. The CAPM is a long-standing and widely used version of these models. The model requires the specification of: (1) the values of the benchmarks that determine the Security Market Line (see Figure 1 above); (2) the relative risk of a security or investment (i.e., beta); and (3) how the benchmarks combine to produce the Security Market Line. Given these specifications, the company's cost of capital is a function of the company's relative

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[36] The NETO Briefing Order states that "[t]he Commission will continue to use the midpoint of the zone of reasonableness as the appropriate measure of central tendency for a diverse group of average risk utilities and the median as the measure of central tendency for a single utility." NETO Briefing Order at fn. 46. It is difficult to see a reason for such different treatment as standard finance theory makes clear it is the use and not the sources of funds that determines the cost of capital.

[37] NETO Briefing Order ¶17.

risk. More precisely, the CAPM calculates the cost of capital for an investment, S (e.g., a particular common stock) as follows:

$$r_s = r_f + \beta_s \times MRP \tag{1}$$

where r_S is the cost of capital for investment S;

r_f is the risk-free interest rate;

β_S is the beta risk measure for the investment S; and

MRP is the market risk premium.

The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. The higher the systematic risk, the greater is the expected return.[38] Thus, the CAPM states that the Security Market Line starts at the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 1, equals the risk-free interest rate). Further, the risk premium of a security over the risk-free rate equals the product of the beta of that security and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

a. The Risk-free Interest Rate

Q. WHAT INTEREST RATES DO YOUR CALCULATIONS REQUIRE?

A. The Commission's methodology relies upon the version of the model that is based upon the long-term risk-free rate.

[38] Systematic risk is the risk that affects the expected return of an investment as opposed to non-systematic (sometimes called diversifiable) risk that does not.

Q. WHAT INTEREST RATE DO YOU USE IN YOUR IMPLEMENTATION OF THE CAPM?

A. The interest rate used in the CAPM must be consistent with the MRP selected. If the MRP is measured relative to 20-year U.S. Treasury bonds, then the risk-free rate should be for a 20-year U.S. Treasury bonds.

Q. DO YOU RECOMMEND THE CURRENT YIELD OR THE FORECAST YIELD AS A MEASURE OF THE RISK-FREE RATE?

A. I do not believe the current yield on the long-term Treasury bond is a good estimate for the risk-free rate that will prevail over the time period the rates in this proceeding are expected to be in effect. For this reason, I use a risk-free rate based on the forecasted value from Blue Chip Economic Indicators. Specifically, I use the 3.2 percent yield on the 10-year U.S. Treasury bond forecasted to be in effect in 2020[39] and adjust upward by 50 bps, which is my estimate of the representative maturity premium for the 20-year over the 10-year Treasury Bond. The resulting value for the unadjusted risk-free rate is 3.7 percent.

b. The Market Risk Premium

Q. HOW WAS THE MRP ESTIMATED IN THE NETO BRIEFING ORDER?

A. The NETO Briefing Order relied upon a methodology proposed by Dr. Avera, the NETO witness in the proceeding. Dr. Avera estimated the MRP by implementing a single stage DCF model for the dividend paying companies in the S&P 500 index using *IBES* earnings growth rate estimates. He then calculated the expected market return by calculating market-value weighted-average of the individual company

[39] Blue Chip Economic Indicators, January 2019.

DCF estimates. To derive the MRP, Dr. Averra subtracted the 6-month average risk-free interest rate on 30-year Treasury bonds.

Q. HOW DO YOU ESTIMATE THE RISK MARKET RISK PREMIUM?

A. I implement the method used by Dr. Avera, but use the forecasted risk-free rate for a 20-year Treasury bond. When calculating the expected return on the S&P 500, I eliminate outliers. Specifically, I eliminate companies with IBES growth rates estimates above 20 percent as high-end outliers, and eliminate companies with IBES growth rates estimates below zero percent as low-end outliers. I also eliminate any ROE estimate that is less than the yield on BBB rated utility debt plus 100 basis points as low-end outliers.

Q. WHAT MRP DID YOU ESTIMATE?

A. Using the methodology above, which is a slightly modified version of Dr. Avera's method, I estimate the MRP to be 9.67 percent.

c. Beta

Q. WHAT BETA ESTIMATES WERE USED IN THE NETO BRIEFING ORDER?

A. The NETO Briefing Order uses beta estimates for the sample companies from *Value Line*. I similarly use *Value Line* as the source of my beta estimates.

Q. CAN YOU MORE FULLY EXPLAIN BETA?

A. The basic idea behind beta is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the risks that cannot be eliminated by diversification. That is, it measures the “systematic” risk of a stock-the extent to which a stock's value fluctuates more or less than average when the market fluctuates.

Diversification is a vital concept in the study of risk and return. (Harry Markowitz won a Nobel Prize for work showing just how important it was.) Over the long run, the rate of return on the stock market has a very high standard deviation, on the order of 20 percent per year. Many individual stocks have much higher standard deviations than this. The stock market's standard deviation is “only” about 15-20 percent because when stocks are combined into portfolios, some of the risk of individual stocks is eliminated by diversification. Some stocks go up when others go down, and the average portfolio return—whether positive or negative—is usually less extreme than that of many individual stocks within it. The fact that the market's actual annual standard deviation is so large means that, in practice, the returns on stocks are positively correlated with one another, and to a material degree. The reason is that many factors that make a particular stock go up or down also affect other stocks. Examples include the state of the economy, the balance of trade, and inflation. Thus, some risk is “non-diversifiable” in that even a well-diversified portfolio of stocks will experience changes in value caused by these shared risk factors. Single-factor equity risk premium models (such as the CAPM) are based upon the assumption that all of the systematic factors that affect stock returns can be considered simultaneously, through their impact on one factor: the market portfolio. Other models derive somewhat less restrictive conditions under which several factors might be individually relevant.

Q. WHAT DOES A PARTICULAR VALUE OF BETA SIGNIFY?

A. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk: it goes up or down by 10 percent on average when the market goes up or down by 10 percent. Stocks with betas above 1.0 exaggerate the swings in the market: stocks with betas of 2.0 tend to fall 20 percent when the market falls 10 percent, for example. Stocks with betas below 1.0 are less volatile than the market. A stock with a beta of 0.5 will tend to rise 5 percent when the market rises 10 percent.

d. Size Adjustment

Q. WHAT IS THE SIZE ADJUSTMENT?

A. The size adjustment is a modification to the CAPM estimates based upon empirical evidence from academic studies documenting a difference between a company's theoretical return as estimated by the CAPM and its realized return. The difference is a function of the size of the entity, where size is measured by its market value capitalization. The appropriate size adjustment is reported by Duff & Phelps[40] and varies with decile. The smallest decile of companies requires the largest addition to the expected return, while the largest decile actually needs a reduction.

[40] Duff & Phelps, *2017 Valuation Handbook,* U.S. Guide to Cost of Capital, 7-10 and 7-11.

Table 2: CAPM ROE Estimates

Company	RFR	Risk Premium	Beta	Unadjusted Ke	Market Cap ($Million)	Size Adjustment	Implied Cost of Equity
	[4]	[5] = [3]-[4]	[6]	[7] = [4]+[5]*[6]	[8]	[9]	[10] = [7] + [9]
ALLETE	3.70%	9.67%	0.65	9.98%	$3,955	0.98%	10.96%
Alliant Energy	3.70%	9.67%	0.60	9.50%	$10,492	0.89%	10.39%
Amer. Elec. Power	3.70%	9.67%	0.55	9.02%	$39,014	-0.35%	8.67%
Ameren Corp.	3.70%	9.67%	0.55	9.02%	$16,933	0.61%	9.63%
AVANGRID Inc.	3.70%	9.67%	0.30	6.60%	$15,410	0.61%	7.21%
CMS Energy Corp.	3.70%	9.67%	0.55	9.02%	$14,771	0.61%	9.63%
Consol. Edison	3.70%	9.67%	0.40	7.57%	$24,182	0.61%	8.18%
DTE Energy	3.70%	9.67%	0.55	9.02%	$21,422	0.61%	9.63%
Duke Energy	3.70%	9.67%	0.50	8.53%	$62,587	-0.35%	8.18%
Edison Int'l	3.70%	9.67%	0.55	9.02%	$18,562	0.61%	9.63%
El Paso Electric	3.70%	9.67%	0.65	9.98%	$2,129	1.66%	11.64%
Entergy Corp.	3.70%	9.67%	0.60	9.50%	$16,155	0.61%	10.11%
Evergy Inc.	3.70%	9.67%	N/A	N/A	$14,956	0.61%	N/A
Eversource Energy	3.70%	9.67%	0.60	9.50%	$21,995	0.61%	10.11%
Exelon Corp.	3.70%	9.67%	0.65	9.98%	$46,184	-0.35%	9.63%
FirstEnergy Corp.	3.70%	9.67%	0.60	9.50%	$20,049	0.61%	10.11%
Hawaiian Elec.	3.70%	9.67%	0.60	9.50%	$4,049	0.98%	10.48%
IDACORP Inc.	3.70%	9.67%	0.55	9.02%	$4,913	0.98%	10.00%
MGE Energy	3.70%	9.67%	0.60	9.50%	$2,230	1.66%	11.16%
NextEra Energy	3.70%	9.67%	0.55	9.02%	$85,543	-0.35%	8.67%
NorthWestern Corp.	3.70%	9.67%	0.55	9.02%	$3,444	1.51%	10.53%
OGE Energy	3.70%	9.67%	0.85	11.92%	$8,179	0.89%	12.81%
Otter Tail Corp.	3.70%	9.67%	0.75	10.95%	$1,922	1.66%	12.61%
Pinnacle West Capital	3.70%	9.67%	0.55	9.02%	$9,869	0.89%	9.91%
PNM Resources	3.70%	9.67%	0.65	9.98%	$3,393	1.51%	11.49%
Portland General	3.70%	9.67%	0.60	9.50%	$4,312	0.98%	10.48%
PPL Corp.	3.70%	9.67%	0.70	10.47%	$22,541	0.61%	11.08%
Public Serv. Enterprise	3.70%	9.67%	0.60	9.50%	$27,493	-0.35%	9.15%
Sempra Energy	3.70%	9.67%	0.75	10.95%	$32,053	-0.35%	10.60%
Southern Co.	3.70%	9.67%	0.50	8.53%	$48,551	-0.35%	8.18%
Unitil Corp.	3.70%	9.67%	0.55	9.02%	$780	2.08%	11.10%
WEC Energy Group	3.70%	9.67%	0.50	8.53%	$23,043	0.61%	9.14%
Xcel Energy Inc.	3.70%	9.67%	0.50	8.53%	$26,876	-0.35%	8.18%
Minimum							7.21%
Maximum							12.81%
Median							10.05%
Midpoint							10.01%
Upper end of ZOR							12.81%
Upper Midpoint							11.41%

Sources and Notes:
[1]: Value Line Investment Analyzer as of 01/31/2019, weighted average dividend yield for dividend paying firms in S&P 500 Index.
[2]: Weighted average of earnings growth rates from IBES for dividend-paying stocks in the S&P 500, accessed 1/31/2019.
[4]: Forecast for 2020 10 Year Treasury Bond Yield + 50bps Spread, January 2019 Blue Chip Economic Indicators.
[6]&[8]: Value Line Investment Analyzer as of 01/31/2019. Evergy Inc. market cap is from Bloomberg, as of 12/31/2018.
[9]: Duff&Phelps 2017 Valuation Handbook U.S. Guide to Cost of Capital, 7-10 and 7-11.

2. The Commission’s Two-Step Discounted Cash Flow Model

a. The Discounted Cash Flow Model

Q. PLEASE DESCRIBE THE THEORETICAL DISCOUNTED CASH FLOW MODEL.

A. The DCF method assumes that the market price of a stock is equal to the present value of the dividends (or cash flows) that its owners expect to receive. The model also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_T}{(1+k)^T} \qquad (2)$$

where “P” is the market price of the stock; “D_t” is the dividend cash flow expected at the end of period t (i.e., subscript period 1, 2, 3 or T in the equation); “k” is the cost of capital; and “T” is the last period in which a dividend cash flow is to be received. The formula says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

One version of the DCF assumes that the growth rate is constant over time, which implies that the formula can be rearranged to estimate the cost of capital as

$$P = \frac{D_1}{(k-g)} \qquad (3)$$

where “D_1” is the dividend expected at the end of the first period, “g” is the perpetual growth rate, and “P” and “k” are the market price and the cost of capital, as before. Equation (3) is a simplified version of Equation (2) that can be solved to yield the well-known “DCF formula” for the cost of capital:

$$\begin{aligned} k &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \qquad (4)$$

where "D_0" is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before. Equation (4) provides that if Equation (3) is satisfied, the cost of equity equals the expected dividend yield plus the (perpetual) expected future (forever constant) growth rate of dividends.

b. The Commission's Two-Step DCF Model

Q. PLEASE DESCRIBE THE COMMISSION'S TWO-STEP DCF MODEL.

A. The Commission's two-step DCF model is a modification of the theoretical DCF model that uses a constant growth of dividends. Instead of estimating the cost of capital in one step, it estimates it in two steps (hence it is called the "two-step" DCF model). The model is articulated in Opinion No. 531:

> The Commission developed the two-step DCF methodology used for determining the cost of capital for individual gas and oil pipelines in a series of orders during the mid-1990s. Under that methodology, the Commission determines a single cost of equity estimate for each member of a proxy group. For the dividend yield component of the DCF model, the Commission derives a single, average dividend yield based on the indicated dividend and the average of the monthly high and low stock prices over a six-month period. The Commission uses a two-step procedure for determining the constant dividend growth component of the model, averaging short-term and long-term growth estimates. Security analysts' five-year forecasts for each company in the proxy group, as published by

> the Institutional Brokers Estimate System (IBES), are used for determining growth for the short term; earnings forecasts made by investment analysts are considered to be the best available estimates of short-term dividend growth because they are likely relied on by investors when making their investment decisions.[29] Long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in GDP. The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.[41]

Q. HOW IS THE DIVIDEND YIELD DETERMINED?

A. The dividend yield is calculated as the six-month average of the highest monthly price and lowest monthly stock price divided into the annualized current quarterly dividend, i.e., the current dividend times four, for each month. The historical six-month average dividend yield is multiplied by 150 percent of the IBES growth rate to give the adjusted dividend yield.

Q. HOW IS THE GROWTH RATE DETERMINED?

A. In Opinion No. 531,[42] the Commission changed the method for determining the growth rate, g, in the formula above. Specifically, the Commission now determines the growth rate as

$$g = (2/3) \times \text{ST growth} + (1/3) \times \text{LT growth} \qquad \textbf{(4)}$$

where the ST growth is the firm-specific 5-year growth rate obtained from IBES (Institutional Brokers Estimate System) or comparable sources. Currently, the Commission uses GDP growth rate forecasts from EIA (Energy Information

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[41] Opinion No. 531 at P 17 (footnotes omitted).
[42] *Id.* at PP 17, 32-41.

Administration), Social Security Administration, and IHS Global Insight (formed by the merger of DRI/McGraw Hill and Wharton Econometrics). Instead of IHS Global Insight, I used Blue Chip Economic Indicators because I do not have access to IHS Global Insight. I use the following steps to calculate the growth rate for each company:

1. Calculate forecast GDP growth from the most recent GDP growth rate forecasts from EIA, Social Security Administration, and Blue Chip Economic Indicators weighted equally.

2. Use the most recent IBES 5-year projected EPS growth rate for each company in the sample.

3. For each company, "g" is calculated as the IBES 5-year growth rate weighted by 2/3 and the weighted-average GDP forecast growth rate weighted by 1/3.

I have also calculated the DCF results using Value Line growth rates in Table 4.

Table 3: DCF ROE Estimates for the FERC Electric Utility Sample

Company	Adjusted Dividend Yield	GDP Growth Forecast	IBES Long Term Growth Rate Forecast	Combined Growth Rate	Implied Cost of Equity
	[4]	[5]	[6]	[7]	[8]
ALLETE	N/A	4.24%	N/A	N/A	-
Alliant Energy	3.25%	4.24%	7.25%	6.25%	9.49%
Amer. Elec. Power	3.59%	4.24%	5.74%	5.24%	8.83%
Ameren Corp.	2.95%	4.24%	7.70%	6.55%	9.49%
AVANGRID Inc.	3.73%	4.24%	9.20%	7.55%	11.28%
CMS Energy Corp.	3.01%	4.24%	7.00%	6.08%	9.09%
Consol. Edison	3.74%	4.24%	2.90%	3.34%	~~*7.08%*~~
DTE Energy	3.30%	4.24%	5.49%	5.07%	8.37%
Duke Energy	4.54%	4.24%	4.41%	4.35%	8.89%
Edison Int'l	3.99%	4.24%	3.75%	3.91%	~~*7.90%*~~
El Paso Electric	2.61%	4.24%	5.10%	4.81%	7.43%
Entergy Corp.	4.19%	4.24%	-3.77%	-1.10%	~~*3.09%*~~
Evergy Inc.	3.43%	4.24%	9.20%	7.55%	10.98%
Eversource Energy	3.25%	4.24%	5.83%	5.30%	8.55%
Exelon Corp.	3.25%	4.24%	8.77%	7.26%	10.51%
FirstEnergy Corp.	3.72%	4.24%	-6.61%	-2.99%	~~*0.72%*~~
Hawaiian Elec.	3.55%	4.24%	7.80%	6.61%	10.16%
IDACORP Inc.	2.56%	4.24%	2.60%	3.15%	~~*5.71%*~~
MGE Energy	N/A	4.24%	N/A	N/A	-
NextEra Energy	2.67%	4.24%	7.45%	6.38%	9.05%
NorthWestern Corp.	3.69%	4.24%	2.59%	3.14%	6.83%
OGE Energy	3.70%	4.24%	-2.25%	-0.09%	~~*3.61%*~~
Otter Tail Corp.	N/A	4.24%	N/A	N/A	-
Pinnacle West Capital	3.54%	4.24%	4.16%	4.19%	7.73%
PNM Resources	2.72%	4.24%	4.10%	4.15%	6.86%
Portland General	3.21%	4.24%	5.05%	4.78%	7.99%
PPL Corp.	5.59%	4.24%	3.59%	3.81%	9.39%
Public Serv. Enterprise	3.52%	4.24%	7.21%	6.22%	9.74%
Sempra Energy	3.27%	4.24%	8.69%	7.21%	10.48%
Southern Co.	5.33%	4.24%	1.68%	2.53%	7.86%
Unitil Corp.	2.98%	4.24%	3.70%	3.88%	6.86%
WEC Energy Group	3.28%	4.24%	4.70%	4.55%	7.83%
Xcel Energy Inc.	3.20%	4.24%	6.60%	5.81%	9.01%
Minimum					6.83%
Maximum					11.28%
Midpoint					9.06%
Upper Midpoint					10.17%

Sources and Notes:
[1]: Bloomberg as of January 31, 2019.
[2]: Bloomberg as of January 31, 2019.
[3]: Bloomberg from 08/01/2018 through 01/31/2019.
[4]: Dividend Yield x (1 + 0.5 x [6]).
[5]: Long Term GDP Growth Rate Forecasts from Social Security Administration, EIA's Annual Energy Outlook 2018 (Table A20), and Blue Chip Economic Indicators, March 2018.
[6]: Long term growth rate estimates from Thomson Reuters as of 01/31/2019.
[7]: ((1/3) x [5]) + ((2/3) x [6]).
[8]: [4] + [7], excluding companies that did not meet all sample selection criteria.
* Companies are excluded for (i) the low spread between cost of equity and cost of debt; and/or (ii) negative long-term IB

Table 4: DCF ROE Results Using Value Line Growth Rates

Company	Adjusted Dividend Yield	GDP Growth Forecast	Value Line Long Term Growth Rate Forecast	Combined Growth Rate	Implied Cost of Equity Before Additional Screens
ALLETE	3.00%	4.24%	4.53%	4.44%	7.44%
Alliant Energy	3.21%	4.24%	4.87%	4.66%	7.87%
Amer. Elec. Power	3.58%	4.24%	5.09%	4.80%	8.39%
Ameren Corp.	2.90%	4.24%	4.53%	4.44%	7.34%
CMS Energy Corp.	2.97%	4.24%	4.66%	4.52%	7.49%
DTE Energy	3.30%	4.24%	5.95%	5.38%	8.68%
Entergy Corp.	4.39%	4.24%	5.74%	5.24%	~~9.63%~~
Evergy Inc.	3.42%	4.24%	8.78%	7.26%	10.69%
MGE Energy	2.21%	4.24%	8.14%	6.84%	9.05%
OGE Energy	3.82%	4.24%	4.46%	4.38%	~~8.21%~~
Otter Tail Corp.	2.90%	4.24%	6.83%	5.96%	8.86%
WEC Energy Group	3.30%	4.24%	6.13%	5.50%	8.80%
AVANGRID Inc.	3.75%	4.24%	10.25%	8.24%	12.00%
Consol. Edison	3.74%	4.24%	3.12%	3.50%	7.24%
Duke Energy	4.57%	4.24%	5.74%	5.24%	9.81%
Eversource Energy	3.24%	4.24%	5.33%	4.97%	8.21%
Exelon Corp.	3.28%	4.24%	10.67%	8.53%	11.80%
FirstEnergy Corp.	4.31%	4.24%	24.35%	17.65%	~~21.96%~~
NextEra Energy	2.64%	4.24%	5.58%	5.13%	7.77%
PPL Corp.	5.55%	4.24%	2.41%	3.02%	8.57%
Public Serv. Enterprise	3.50%	4.24%	5.74%	5.24%	8.73%
Southern Co.	5.41%	4.24%	4.81%	4.62%	10.04%
Unitil Corp.	N/A	4.24%	n/a	N/A	-
Edison Int'l	4.04%	4.24%	6.35%	5.64%	9.68%
El Paso Electric	2.61%	4.24%	4.57%	4.46%	7.07%
Hawaiian Elec.	3.49%	4.24%	4.32%	4.29%	7.78%
IDACORP Inc.	2.58%	4.24%	3.93%	4.03%	6.61%
NorthWestern Corp.	3.69%	4.24%	2.48%	3.07%	6.76%
Pinnacle West Capital	3.59%	4.24%	6.92%	6.03%	9.61%
PNM Resources	2.75%	4.24%	6.41%	5.69%	8.43%
Portland General	3.19%	4.24%	3.46%	3.72%	6.91%
Sempra Energy	3.29%	4.24%	9.82%	7.96%	11.25%
Xcel Energy Inc.	3.15%	4.24%	3.64%	3.84%	6.99%
Minimum					6.61%
Maximum					12.00%
Median					8.43%
Midpoint					9.30%
Upper End of FERC ZOR					12.00%
Upper Midpoint					10.65%

A comparison of Tables 3 and 4 above makes clear that the use of IBES growth rates and the exclusion of Value Line growth rates results in a lower midpoint and a non-trivially lower maximum.

3. Expected Earnings Method

Q. HOW DID THE NETO BRIEFING ORDER IMPLEMENT THE EXPECTED EARNINGS METHOD?

A. The expected earnings method uses the expected or forecast return on book equity as provided by *Value Line*. The forecast used is the expected ROE 3 to 5 years in the future. Because the forecast is assumed to be an ROE based upon the company's book equity in the last year of the period, an adjustment is needed to convert the forecast ROE to ROE over an average book value of equity over the period. The adjustment used is to multiply the forecast ROE by an adjustment factor equal to 2*(1 + 5-yr. change in equity)/(2 + 5-yr. change in equity).

Q. ARE THE EXPECTED EARNINGS MARKET BASED ESTIMATES?

A. No. They are based on accounting data. They have the advantage of being a book rate of return, which is comparable to the allowed ROE on a book value rate base.

Table 5: Expected Earnings Method Applied to the FERC Electric Sample

Company	2021-23 Expected Return on Equity [1]	Adjustment Factor [2]	Adjusted Return on Equity [3]=[1]*[2]
ALLETE	9.00%	1.015	9.14%
Alliant Energy	10.50%	1.005	10.55%
Amer. Elec. Power	11.00%	1.022	11.25%
Ameren Corp.	10.50%	1.021	10.72%
AVANGRID Inc.	6.50%	1.007	6.55%
CMS Energy Corp.	14.00%	1.032	14.45%
Consol. Edison	8.50%	1.013	8.61%
DTE Energy	11.00%	1.030	11.33%
Duke Energy	8.50%	1.011	8.59%
Edison Int'l	12.50%	1.020	12.75%
El Paso Electric	8.50%	1.013	8.61%
Entergy Corp.	11.00%	1.029	11.32%
Evergy Inc.	9.50%	0.991	9.41%
Eversource Energy	9.50%	1.014	9.64%
Exelon Corp.	9.50%	1.022	9.71%
FirstEnergy Corp.	16.50%	1.039	17.15%
Hawaiian Elec.	9.50%	1.021	9.70%
IDACORP Inc.	9.50%	1.017	9.66%
MGE Energy	9.00%	1.045	9.40%
NextEra Energy	13.00%	1.023	13.29%
NorthWestern Corp.	9.00%	1.012	9.11%
OGE Energy	11.50%	1.013	11.64%
Otter Tail Corp.	11.00%	1.042	11.47%
Pinnacle West Capital	10.50%	1.017	10.67%
PNM Resources	9.50%	1.025	9.74%
Portland General	9.00%	1.014	9.12%
PPL Corp.	13.50%	1.029	13.89%
Public Serv. Enterprise	11.00%	1.018	11.20%
Sempra Energy	12.00%	1.028	12.34%
Southern Co.	12.50%	1.019	12.74%
Unitil Corp.	N/A	N/A	N/A
WEC Energy Group	12.00%	1.013	12.16%
Xcel Energy Inc.	10.50%	1.021	10.72%
Minimum			6.5%
Maximum			17.1%
Midpoint			11.8%
Maximum (outlier tested)			14.4%
Upper Midpoint (outlier tested)			12.5%

Sources and Notes:
[1]: Value Line Investment Analyzer as of 01/31/2019.
FirstEnergy Corp. is encluded from the ROE estimation because it fails the outlier test.
Unitil Corp. is excluded from the sample due to data inavailability.

4. The Risk Premium Method

Q. PLEASE DESCRIBE THE RISK PREMIUM METHOD AS IMPLEMENTED IN THE NETO BRIEFING ORDER.

A. The risk premium method compares the Commission allowed ROE for Commission regulated companies with a measure of the concurrent cost of debt using regression analysis. The concept is that the market cost of equity is greater than the cost of debt because equity is riskier. The cost of equity will change as the cost of debt changes, but the change is not likely to be one for one. This means that a one percentage point increase in the cost debt will not result in a one percentage point change in the cost of equity.

Q. WHAT ARE THE INPUT DATA FOR THE RISK PREMIUM ANALYSIS?

A. The data are the allowed ROEs for Commission regulated electric transmission companies and the six-month average yield on BBB-rated utility debt as reported by Moody's. The relationship between the change in interest rates (independent variable) and the allowed ROE (dependent variable) is estimated using linear regression. The method allows for two estimates: one using a historical yield on BBB-rated debt; and one using a forecast yield on BBB-rated debt.

Q. WHAT IS THE ESTIMATE USING THE RISK PREMIUM METHOD?

A. The results are 10.14 percent using a historical measure of the BBB-rated utility debt and 10.73 using a forecast of the BBB-rated utility debt for an average of 10.44.[43] These are the estimates reported by Mr. Adrien M. McKenzie in his

[43] Please refer to Attachment PGE-0017-5, Risk Premium Approach in Mr. McKenzie's testimony for the underlying calculations.

testimony for Pacific Gas & Electric in Exhibit No. PGE-0017 in Docket No. ER19-13-000. There are to my knowledge no new results that need to be considered and hence no new analysis needs to be conducted.

C. The Range of Reasonableness

Q. WHAT ARE THE RESULTS OF THE APPLICATION OF THE COMMISSION'S REVISED ROE METHODOLOGY TO THE FERC ELECTRIC UTILITY SAMPLE?

A. **Error! Reference source not found.** below presents the summary information for each of the ROE estimation methods for the companies in the FERC Electric Utility Sample using data through January 31, 2019.[44] **Error! Reference source not found.** also reports the minimum, maximum, midpoint, and median ROE estimates as well as the ZOR for each method and the Composite ZOR. The Composite ZOR ranges from a low of 6.7 percent to a high of 12.5 percent with a midpoint of 9.6 percent. The midpoint of the upper half of the range is 11.12 percent.

Table 6: Zone of Reasonableness[45]

	DCF (IBES Growth Rates)	CAPM	Expected Earnings	Composite Zone of Reasonableness	Risk Premium*
Minimum	6.8%	7.2%	6.5%	6.9%	10.1%
Maximum	11.3%	12.8%	14.4%	12.8%	10.7%
Midpoint	9.1%	10.0%	10.5%	9.9%	10.4%
Zone of Reasonableness	6.8% - 11.3%	6.8% - 11.7%	6.5% - 14.4%	6.7% - 12.5%	
Midpoint of Upper-Half Zone of Reasonableness* **	**10.2%**	**11.4%**	**12.5%**	**11.12%**	

Notes:
DCF, Expected Earnings, and CAPM models are updated as of 01/31/2019.
CAPM estimates reflect a size premium based on Duff & Phelps 2017 Valuation Handbook.
* Risk Premium model does not produce a Zone of Reasonableness; midpoint is average of two point estimates derived using Avera methodology applied to updated 2018 data.
** Midpoint of Upper-Half Zone of Reasonableness for the Composite Zone of Reasonableness is calculated as the average

[44] I restrict the estimates to be greater than the yield on BBB-rated utility debt by at least 100 bps and less than 1.5 times the median estimate.
[45] Briefing Order at pp. 17-32.

Q. WHERE IN THE RANGE SHOULD SCE'S ROE BEFORE INCENTIVES OR OTHER ADDERS FALL?

A. Because SCE, as discussed above, is higher risk than the FERC Electric Utility Sample, I recommend that it be placed in the upper half of the ZOR. The Commission has previously allowed entities of higher risk to be placed in the upper half of the ZOR[46] and, in the NETO Briefing Order, acknowledged such placement can be appropriate.[47] Specifically, I recommend the midpoint of the upper half of the ZOR be used.

The NETO Briefing Order proposes to use different methods to determine ROEs for below or above average risk utilities based on filing status as either a single- or group-filing utility. Specifically, for group-filers, the Commission proposes to use midpoints of the upper half of the ZOR for above average risk group-filers, while for single-filers, the Commission proposes to use the median.[48] As noted earlier, according to finance theory, the cost of capital for an entity depends on the use of funds not the source of funds.[49] Consequently, there is no finance or economic

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[46] *See e.g.*, Opinion No. 445, 92 FERC 61,070 at 61,266-61,267 267 ("[We] find that SoCal Edison is more risky than the comparison group. Therefore, the appropriate ROE for SoCal Edison should be above the midpoint of returns indicated for the comparison group. Therefore, we will establish SoCal Edison's ROE at the midpoint of the upper half of the zone of reasonableness. That zone is 11.02-12.44 percent with a midpoint of 11.73. However, because this return exceeds SoCal Edison's own request, we will adjust the indicated return downward to 11.60 percent.") (citations omitted).

[47] NETO Briefing Order at P 32 ("We propose to use the midpoint/medians of the resulting lower and upper halves of the zone of reasonableness to determine ROEs for below or above average risk utilities, respectively.").

[48] NETO Briefing Order at pp. 17-32.

[49] Brealey, Myers and Allen, "Principles of Corporate Finance," 11th Edition, 2014, p. 219.

reason to treat single-filers and group-filers differently and the NETO Briefing Order presents no analysis that demonstrates a reason for such difference.

Importantly, using the proposal to treat group and single-filers differently would result in two assets of equal risk being awarded a different level return on equity, which is contrary to the notion that the allowed ROE should be commensurate with that of entities of similar risk.

Additionally, the most recent Commission Order that I am aware of, which pertains to an above average risk applicant, relied on the Upper Midpoint.[50]

For these reasons, I consider the upper midpoint to be a reasonable point estimate for SCE's ROE.

Q. BASED UPON THESE RESULTS AND OTHER FACTORS, WHAT IS YOUR RECOMMENDED ROE?

A. I recommend that SCE's request to set the allowed ROE be set at 11.12 percent before consideration of incentives or other adders. This is higher than SCE's most recently approved ROE and higher than what is currently under consideration in Docket ER 18-169-000. However, the Commission's approach to ROE determination has changed as have market conditions and SCE's risk profile. Consequently, this is not an inconsistency.

Q. DO YOU HAVE OTHER OBSERVATIONS REGARDING SCE'S ROE?

A. Yes. As noted previously, SCE participates in the CAISO and has in the past received incentives for specific projects. I recommend this policy be continued.[51]

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[50] Order 521.

[51] See the Testimony of Dr. Stern for a discussion of the benefits of participating in CAISO and the projects that were awarded incentive adders by the Commission.

Further, as discussed above, SCE faces substantial risks from wildfire liabilities that may render the traditional Commission ZOR inadequate to meet investor expectations regarding the all-in return for taking on such risks. Consequently, I developed ROE estimates for an alternative sample, which looks to a broader set of companies to consider what ZOR applies to such companies. I note that even this alternative ZOR may be inadequate because the potential risks associated with wildfires are extraordinarily large, ongoing and because California law operates with an uncommon approach to such liabilities.[52]

VII. EXPANDED ZONE OF REASONABLENESS

A. Sample selection

Q. HOW DO YOU SELECT AN ALTERNATIVE SAMPLE?

A. I selected a group of Capital-Intensive Network Industry ("CINI") companies after considering the characteristics of the electric utility industry.

Regulated electric utilities are capital intensive and operate networks of assets. Thus, the sample captures two key characteristics of the electric utility industry's assets – namely that each dollar invested generate relatively low revenue and that the assets are not readily re-deployed to a different use (contrary to, for example, the liquid assets owned by a bank). I measure capital intensity as the amount of capital (in dollars) that is needed to generate a dollar of revenue. The higher that figure is the more capital intensive a company is.[53] Financial analysts commonly

[52] As noted earlier, I make no recommendation regarding the magnitude of potential liability associated with wildfire risks, the recovery of such liabilities or the magnitude of the return investors may seek to take on such risks.

[53] Financial analysts commonly calculate the so-called asset turnover ratio, which is revenue per dollar investment thus capital intensity equals 1 divided by the asset turnover ratio. See, for example, Ross, Westerfield & Jaffe, "Corporate Finance," 10th edition, 2013, pp. 52-53.

calculate the so-called asset turnover ratio, which is revenue per dollar of investment. The lower the revenue per dollar invested, the more capital is needed to generate revenue and the higher the capital intensity. Across industries, the capital intensity differs widely, with regulated industries commonly being among the most capital intensive in the economy, and the regulated electric utility industry is capital intensive.[54]

In addition to electric utilities, the following industries are also network industries: water, natural gas distribution, oil and natural gas pipelines, pipeline master limited partnerships ("MLPs"), telecom services, telecom utility, cable TV, trucking, railroads, and air transport. Consequently, the CINI sample includes companies from these industries that meet the selection criteria and have sufficient data for estimation.

Q. HOW DID YOU DETERMINE WHAT COMPANIES TO INCLUDE IN THE CAPITAL-INTENSIVE NETWORK SAMPLE?

A. The CINI sample is derived from the universe of publicly traded U.S. domiciled companies on *Value Line* with industry classifications that are network based and that empirically can be shown to be capital intensive. The initial group of companies for which I examined capital intensity and other characteristics consisted of 296 companies, including 41 electric utilities, which I eliminated.

After the elimination of electric utilities, 255 companies remain, but a very large number are also eliminated because they do not pay dividends, have recently

[54] To be included in the CINI Sample, individual companies must have an asset turnover ratio of less than 1.60.

engaged in merger and acquisition activity, have a non-investment grade credit rating (or no credit rating), or simply lack data. Consequently, I end up with a sample of 27 companies, whose characteristics are displayed below.

Table 7: Companies in the Capital Intensive Network Industries Sample

Company	Annual Revenue (Q3 2018) ($MM)	Market Cap. (Q3 2018) ($MM)	S&P Credit Rating
Delta Air Lines	$43,925	$39,686	BBB-
Southwest Airlines	$21,519	$35,168	BBB+
FedEx Corp.	$67,205	$65,007	BBB
United Parcel Serv.	$70,988	$102,379	A+
Atmos Energy	$3,116	$10,426	A
Chesapeake Utilities	$697	$1,423	A-
NiSource Inc.	$5,021	$9,407	BBB+
Northwest Natural	$721	$1,960	A
ONE Gas Inc.	$1,632	$4,277	A
Southwest Gas	$2,834	$3,967	BBB+
Spire Inc.	$1,965	$3,779	A-
Enable Midstream Part.	$3,287	$7,004	BBB-
Enterprise Products	$35,779	$63,318	BBB+
Magellan Midstream	$2,634	$15,604	BBB+
CSX Corp.	$11,970	$62,290	BBB+
GATX Corp.	$1,357	$3,191	BBB
Kansas City South'n	$2,680	$11,890	BBB-
Union Pacific	$22,525	$118,559	A-
Heartland Express	$630	$1,666	n/a
Ryder System	$8,082	$4,009	BBB+
Amer. States Water	$430	$2,205	A+
Amer. Water Works	$3,411	$15,928	A
Middlesex Water	$136	$780	A
York Water Co. (The)	$49	$390	A-
MDU Resources	$4,487	$5,194	BBB+
EOG Resources	$16,216	$69,860	A-
National Fuel Gas	$1,593	$4,815	BBB

As can be seen from the sample above, the resulting sample has regulated entities from the natural gas distribution, the pipeline industry, and the water utility industry. The remaining industries in the resulting sample are mostly not regulated: airlines, railroads, transportation, and diversified gas companies.[55]

1. Capital Intensity Screen

Q. PLEASE EXPLAIN HOW YOU MEASURE CAPITAL INTENSITY.

A. To ensure a company truly is capital intensive, I calculated the five-year average Asset-Turnover for each company and included only those with a measure below 1.6. Specifically, I calculated

$$Asset\ Turnover\ = \frac{Revenue}{Average\ Total\ Assets}$$

where revenue is net sales revenue and average total assets is the average of balance sheet total assets from the prior year and the current year.

The five-year average asset turnover ratio is calculated as the average of asset turnover from each of the last five years leading up to 2017, which is the most recent year for which I have sufficient data for all companies.

B. Calculating the Commission ROE for the Alternative Sample

Q. HOW DO YOU CALCULATE THE RANGE OF ROE ESTIMATES FOR THE ALTERNATIVE SAMPLE?

A. I rely on the same estimation methods as for the Electric Utility Sample. First, I calculate the Commission two-stage DCF, the CAPM, and the Expected Earnings for each of the samples companies. I do not calculate a risk premium ROE as most

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[55] I started considered the following industries: electric utilities, water utilities, natural gas distribution utilities, oil and natural gas pipelines, pipeline master limited partnerships, telecom services, telecom utilities, cable TV, trucking, railroads and air transportation from Value Line. From the original group of 296 companies, I eliminated 89 companies for lack of an investment grade credit rating, 99 for dividend cuts or no dividend payment, 40 for mergers and acquisitions, 5 due to a small size, and 7 for a low capital intensity. Additionally, I eliminated the overlap with the Electric Utility Sample.

of the companies do not have an allowed ROE and even fewer have a Commission-allowed ROE. In implementing the two-stage DCF, I rely on the same GDP growth rate as for the Electric Utility Sample. Similarly, the risk-free rate and the MRP is the same as for the Electric Utility Sample when implemented for the CINI sample. Second, I determine the minimum, maximum, midpoint and upper midpoint for each estimation method and implement outlier tests in the same manner as for the Electric Utility Sample. I rely on the same methods as described above for the Electric Utility Sample. Finally, I summarize the results.

Q. WHAT ARE YOUR RESULTS FOR THE CAPM?

A. The results from the CAPM are displayed in Table 8 below. The range is 9.4 percent to 17.8 percent.

Table 8: FERC CAPM ROE for CINI Sample

Company	RFR	Risk Premium	Beta	Unadjusted Ke	Market Cap ($Million)	Size Adjustment	Implied Cost of Equity
	[1]	[2]	[3]	[4] = [1] + [2]x [3]	[5]	[6]	[7] = [4] + [6]
Delta Air Lines	3.70%	9.67%	1.20	15.3%	$34,624	-0.35%	15.0%
Southwest Airlines	3.70%	9.67%	1.15	14.8%	$26,316	-0.35%	14.5%
Atmos Energy	3.70%	9.67%	0.60	9.5%	$10,141	0.89%	10.4%
Chesapeake Utilities	3.70%	9.67%	0.65	10.0%	$1,306	1.72%	11.7%
NiSource Inc.	3.70%	9.67%	0.50	8.5%	$9,199	0.89%	9.4%
Northwest Natural	3.70%	9.67%	0.60	9.5%	$1,738	1.66%	11.2%
ONE Gas Inc.	3.70%	9.67%	0.65	10.0%	$4,111	0.98%	11.0%
Southwest Gas	3.70%	9.67%	0.70	10.5%	$3,729	0.98%	11.4%
Spire Inc.	3.70%	9.67%	0.65	10.0%	$3,711	0.98%	11.0%
Enable Midstream Part.	3.70%	9.67%	1.25	15.8%	$5,706	0.89%	16.7%
Enterprise Products	3.70%	9.67%	1.30	16.3%	$52,908	-0.35%	15.9%
Magellan Midstream	3.70%	9.67%	1.20	15.3%	$12,850	0.61%	15.9%
CSX Corp.	3.70%	9.67%	1.20	15.3%	$52,405	-0.35%	15.0%
GATX Corp.	3.70%	9.67%	1.30	16.3%	$2,718	1.51%	17.8%
Kansas City South'n	3.70%	9.67%	1.10	14.3%	$9,753	0.89%	15.2%
Union Pacific	3.70%	9.67%	1.10	14.3%	$101,143	-0.35%	14.0%
Heartland Express	3.70%	9.67%	0.90	12.4%	$1,484	1.72%	14.1%
Ryder System	3.70%	9.67%	1.30	16.3%	$2,551	1.51%	17.8%
Amer. States Water	3.70%	9.67%	0.70	10.5%	$2,444	1.51%	12.0%
Amer. Water Works	3.70%	9.67%	0.55	9.0%	$16,147	0.61%	9.6%
Middlesex Water	3.70%	9.67%	0.75	11.0%	$851	2.08%	13.0%
York Water Co. (The)	3.70%	9.67%	0.75	11.0%	$407	2.68%	13.6%
EOG Resources	3.70%	9.67%	1.45	17.7%	$51,483	-0.35%	17.4%
MDU Resources	3.70%	9.67%	1.00	13.4%	$4,567	0.98%	14.3%
National Fuel Gas	3.70%	9.67%	1.00	13.4%	$4,460	0.98%	14.3%
FedEx Corp.	3.70%	9.67%	1.15	14.8%	$42,033	-0.35%	14.5%
United Parcel Serv.	3.70%	9.67%	0.90	12.4%	$83,993	-0.35%	12.1%
						Min	9.4%
						Max (outlier tested)	17.8%
						Median	14.1%
						Midpoint	13.6%

Q. WHAT ARE THE RESULTS FROM THE COMMISSION TWO-STAGE DCF?

A. While the Commission CAPM ZOR includes all sample companies, the Commission outlier test removes two companies from the Commission two-stage DCF, of which one is slightly above the upper end of the Commission's ZOR. The results are displayed in Table 9 below, which shows a range of 6.3 to 18.2 percent.

Table 9: FERC Two_Stage DCF ROE for CINI Sample

Company	S&P Credit Rating [1]	Dividend Yield [3]	Adjusted Dividend Yield [4]	GDP Growth Forecast [5]	IBES Growth Estimate [6]	Combined Growth Rate [7]	Implied Cost of Equity [8]
Delta Air Lines	BBB-	2.53%	2.69%	4.21%	16.82%	12.62%	15.3%
Southwest Airlines	BBB+	1.16%	1.23%	4.21%	15.90%	12.00%	13.2%
FedEx Corp.	BBB	1.14%	1.19%	4.21%	9.71%	7.87%	9.1%
United Parcel Serv.	A+	3.22%	3.37%	4.21%	11.59%	9.13%	12.5%
Atmos Energy	A	2.13%	2.19%	4.21%	6.45%	5.70%	7.9%
Chesapeake Utilities	A-	1.75%	-	4.21%	n/a	-	-
NiSource Inc.	BBB+	3.00%	3.08%	4.21%	5.92%	5.35%	8.4%
Northwest Natural	A	2.89%	2.95%	4.21%	4.00%	4.07%	7.0%
ONE Gas Inc.	A	2.30%	2.36%	4.21%	5.50%	5.07%	7.4%
Southwest Gas	BBB+	2.63%	2.70%	4.21%	6.20%	5.54%	8.2%
Spire Inc.	A-	3.06%	3.10%	4.21%	2.70%	3.20%	6.3%
Enable Midstream Part.	BBB-	8.05%	8.33%	4.21%	8.10%	6.80%	15.1%
Enterprise Products	BBB+	6.24%	6.48%	4.21%	9.39%	7.66%	14.1%
Magellan Midstream	BBB+	5.90%	6.10%	4.21%	8.02%	6.75%	12.9%
CSX Corp.	BBB+	1.25%	1.36%	4.21%	23.21%	16.88%	18.2%
GATX Corp.	BBB	2.17%	2.27%	4.21%	12.00%	9.40%	11.7%
Kansas City South'n	BBB	1.34%	1.41%	4.21%	14.70%	11.20%	12.6%
Union Pacific	A-	2.12%	2.26%	4.21%	18.27%	13.58%	15.8%
Heartland Express	#N/A N/A	0.41%	0.45%	4.21%	27.11%	19.48%	19.9%
Ryder System	BBB+	3.32%	3.50%	4.21%	14.61%	11.14%	14.6%
Amer. States Water	A+	1.76%	1.81%	4.21%	6.00%	5.40%	7.2%
Amer. Water Works	A	2.04%	2.11%	4.21%	8.20%	6.87%	9.0%
Middlesex Water	A	1.93%	-	4.21%	n/a	-	-
York Water Co. (The)	A-	2.13%	-	4.21%	n/a	-	-
MDU Resources	BBB+	2.99%	-	4.21%	n/a	-	-
EOG Resources	A-	0.72%	0.97%	4.21%	102.56%	69.78%	70.7%
National Fuel Gas	BBB	3.12%	-	4.21%	n/a	-	-
						Maximum	70.7%
						Minimum	6.3%
						Median	12.6%
						Maximum (Outlier Tested)	18.2%

Q. WHAT ARE THE RESULTS FROM THE EXPECTED EARNINGS MODEL?

A. In the case of the application of the Expected Earnings model, several companies fall outside the Commission's conventionally determined ZOR. However, the range of estimates is very wide and range from 9.9% to 18.0%.

Table 10: FERC Expected Earnings ROE for CINI Sample

Company	2021-23 Expected Return on Common Equity	Adjustment Factor	Adjusted Return on Common Equity (full sample)
[1]	[4]	[5]	[6]
Delta Air Lines	25.5%	1.04	26.4%
Southwest Airlines	23.0%	1.02	23.4%
FedEx Corp.	18.0%	1.03	18.6%
United Parcel Serv.	NA	1.10	NA
Atmos Energy	11.0%	1.02	11.3%
Chesapeake Utilities	10.0%	1.05	10.5%
NiSource Inc.	11.5%	1.01	11.6%
Northwest Natural	12.0%	1.02	12.2%
ONE Gas Inc.	11.0%	1.02	11.2%
Southwest Gas	9.5%	1.04	9.9%
Spire Inc.	10.0%	1.02	10.2%
Enable Midstream Part.	11.5%	1.02	11.7%
Enterprise Products	24.0%	1.00	24.1%
Magellan Midstream	46.0%	1.01	46.5%
CSX Corp.	30.5%	1.00	30.6%
GATX Corp.	11.0%	1.01	11.1%
Kansas City South'n	16.5%	1.01	16.7%
Union Pacific	43.0%	0.99	42.4%
Heartland Express	14.0%	1.04	14.5%
Ryder System	11.5%	1.03	11.8%
Amer. States Water	14.0%	1.01	14.1%
Amer. Water Works	10.5%	1.03	10.8%
Middlesex Water	13.0%	1.02	13.2%
York Water Co. (The)	13.5%	1.02	13.7%
MDU Resources	14.0%	1.03	14.5%
EOG Resources	17.0%	1.07	18.2%
National Fuel Gas	16.5%	1.06	17.5%

	Full Sample
Minimum	9.9%
Maximum	46.5%
Median (Outlier Tested)	12.0%
Maximum (Outlier Tested)	18.0%

VIII. CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE ROE FOR SCE GIVEN THE RESULTS GENERATED BY THE FERC ELECTRIC UTILITY SAMPLE?

A. As discussed in Section V above, the majority of the companies in the Commission's traditional electric utility sample face less risk than SCE, even before any consideration of the potentially enormous wildfire liabilities that SCE may be exposed to. Consequently, SCE needs an ROE above what is awarded to average risk utilities and, given the substantial additional risk; I recommend it be awarded an ROE of 11.12% before any consideration of incentive or other adders. Additionally, I recommend that SCE be granted incentive adders for CAISO participation consistent with the Commission's historical approach.

Lastly, I find that an alternative and broader sample of companies that represent Capital-Intensive Network Industries are illustrative of the kind of return such companies' investors may require. Looking to the Commission's approach to determining the ROE, I find a range of 6.3% to 18.2% with multiple observations above or below that range. These companies are similar to SCE in that they (1) operate a network and (2) are capital-intensive. Their risks are, on average, higher than that of the Electric Utility Sample, but the specific risk exposure differs across industries and companies.

In my opinion, the Capital-Intensive Network Industries sample provides an alternative sample to consider when determining SCE's ROE, taking into account that SCE has higher risks than the average utility.

Q. HOW SHOULD SCE'S WILDFIRE RISKS BE TREATED?

A. As noted in the introduction, wildfire risks are ultimately an asymmetric risk and the treatment hereof is not part of my testimony.

For a discussion regarding how SCE's wildfires affects SCE's financial condition and the re-numeration necessary to insure investors receive a return commensurate with the risks associated with the wildfire risk, I refer to the Direct Testimony of Mr. Frank Graves.[56] The Direct Testimony of Mr. Dan Wood[57] summarizes the return that SCE is requesting in this proceeding given SCE's risk profile, including the wildfire risks.

Q. DO YOU HAVE ANY OTHER COMMENTS?

A. Yes, I recognize that the Commission is evaluating its approach to ROE determination (in the Commission's NOI in Docket PL19-4-000) and therefore I may revisit my calculations should the Commission change its methodology.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[56] Exhibit No. SCE-22 and SCE-24.
[57] Exhibit No. SCE-19.

DECLARATION

I, Bente Villadsen, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on April 9, 2019 in Boston, Massachusetts.

Bente Villadsen

Bente Villadsen

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER19-______-000**
	)	

EXHIBIT SCE-26

EXHIBIT TO THE TESTIMONY OF DR. BENTE VILLADSEN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

BENTE VILLADSEN

Principal

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Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is the review of regulatory practices regarding the return on equity, capital structure, recovery of costs and capital expenditures as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, Dr. Villadsen was a faculty member at Washington University in St. Louis, University of Michigan, and University of Iowa.

She has taught financial and managerial accounting as well as econometrics, quantitative methods, and economics of information to undergraduate or graduate students. Dr. Villadsen serves as the president of the Society of Utility Regulatory Financial Analysts for 2016-2018.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Credit Issues in the Utility Industry
- Damages and Valuation (incl. international arbitration)

- Utility valuation
- Lost Profit for construction, oil&gas, utilities
- Valuation of construction contract
- Damages from the choice of inaccurate accounting methdology

EXPERIENCE

Regulatory Finance

- Dr. Villadsen has testified on cost of capital and capital structure for many regulated entities including electric and gas utilities, pipelines, railroads, and water utilities in many jurisdictions including at the FERC, the Surface Transportation Board, the states of Alaska, Arizona, California, Illinois, New Mexico, New York, Oregon, and Washington as well as in the provinces of Alberta and Ontario.

- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board (STB) and submitted expert reports on the determination of the cost of equity for U.S. freight railroads. The STB agreed to continue to use two estimation methods with the parameters suggested.

- For several electric, gas and transmission utilities as well as pipelines in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.

- Dr. Villadsen has estimated the cost of capital and recommended an appropriate capital structure for natural gas and liquids pipelines in Canada, Mexico, and the US. using the jurisdictions' preferred estimation technique as well as other standard techniques. This work has been used in negotiations with shippers as well as before regulators.

- For the Ontario Energy Board Staff, Dr. Villadsen submitted evidence on the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program.

- She has estimated the cost of equity on behalf of Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.

- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.

- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.
- She has worked on behalf of infrastructure funds, pension funds, utilities and others on understanding and evaluating the regulatory environment in which electric, natural gas, or water utilities operate for the purpose of enhancing investors ability to understand potential investments. She has also provided advise and testimony in the approval phase of acquisitions.
- On behalf of utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated

electric utilities, transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.

- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.
- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties. For the owner of Heathrow and Gatwick Airport facilities, she has assisted in estimating the cost of capital of U.K. based airports. The resulting report was filed with the U.K. Competition Commission.
- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.

- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.
- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.
- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).

- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 12 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.

Accounting and Corporate Finance

- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.
- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.
- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For

the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.

- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.
- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.

- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.
- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.
- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.
- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.
- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.

- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.

- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.

- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.

- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

BOOKS

"*Risk and Return for Regulated Industries*," (with Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe) Elsevier, May 2017.

PUBLICATIONS AND REPORTS

"Impact of New Tax Law on Utilities' Deferred Taxes," (with Mike Tolleth and Elliott Metzler), *CRRI 37'th Annual Eastern Conference*, June, 2018.

"Implications of the New Tax Law for Regulated Utilities," The Brattle Group, January 2018.

"Using Electric and Gas Forwards to Manage Market Risks: When a power purchase agreement with a utility is not possible, standard forward contracts can act as viable hedging instruments," *North American Windpower*, May 2017, pp. 34-37.

"*Managing Price Risk for Merchant Renewable Investments: Role of Market Interactions and Dynamics on Effective Hedging Strategies*," (with Onur Aydin and Frank Graves), Brattle Whitepaper, January 2017.

"Aurizon Network 2016 Access Undertaking: Aspects of the WACC," (with Mike Tolleth), filed with the *Queensland Competition Authority*, Australia, November 2016.

"Report on Gas LDC multiples," with Michael J. Vilbert, *Alaska Industrial Development and Export Authority*, May 2015.

"Aurizon Network 2014 Draft Access Undertaking: Comments on Aspects of the WACC," prepared for Aurizon Network and submitted to the *Queensland Competition Authority*, December 2014

"Brattle Review of AE Planning Methods and Austin Task Force Report." (with Frank C. Graves) September 24, 2014.

Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

"Estimating the Cost of Debt," (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

"Calculating the Equity Risk Premium and the Risk Free Rate," (with Dan Harris and Francesco LoPasso), prepared for *NMa and Opta, the Netherlands*, November 2012.

"Shale Gas and Pipeline Risk: Earnings Erosion in a More Competitive World," (with Paul R. Carpenter, A. Lawrence Kolbe, and Steven H. Levine), *Public Utilities Fortnightly*, April 2012.

"Survey of Cost of Capital Practices in Canada," (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

"Public Sector Discount Rates" (with rank Graves, Bin Zhou), *Brattle* white paper, September 2011

"FASB Accounting Rules and Implications for Natural Gas Purchase Agreements," (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

"IFRS and You: How the New Standards Affect Utility Balance Sheets," (with Amit Koshal and Wyatt Toolson), *Public Utilities Fortnightly*, December 2010.

"Corporate Pension Plans: New Developments and Litigation," (with George Oldfield and Urvashi Malhotra), Finance Newsletter, Issue 01, *The Brattle Group*, November 2010.

"Review of Regulatory Cost of Capital Methodologies," (with Michael J. Vilbert and Matthew Aharonian), *Canadian Transportation Agency*, September 2010.

"Building Sustainable Efficiency Businesses: Evaluating Business Models," (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

"Understanding Debt Imputation Issues," (with Michael J. Vilbert and Joe Wharton and *The Brattle Group* listed as an author), *Edison Electric Institute*, June 2008.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," *Public Utilities Fortnightly*, August 2005 (with A. Lawrence Kolbe and Michael J. Vilbert).

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," (with A. Lawrence Kolbe and Michael J. Vilbert, and with "*The Brattle Group*" listed as author), *Edison Electric Institute,* April 2005.

"Communication and Delegation in Collusive Agencies," *Journal of Accounting and Economics*, Vol. 19, 1995.

"Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services" (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

SELECTED PRESENTATIONS

"Decoupling and its Impact on Cost of Capital" presented to *SURFA Members and Friends*, February 27, 2019.

"Current Issues in Cost of Capital" presented to *EEI Members*, July 23, 2018.

"Introduction to Capital Structure & Liability Management", presented at *the American Gas Association (AGA)/Edison Electric Institute (EEI) "Introduction and Advanced Public Utility Accounting Courses",* August 21, 2018.

"Lessons from the U.S. and Australia" presented at *Seminar on the Cost of Capital in Regulated Industries: Time for a Fresh Perspective?* Brussels, October 2017.

"Should Regulated Utilities Hedge Fuel Cost and if so, How?" presented at *SURFA's 49 Financial Forum*, April 20-21, 2017.

"Transmission: The Interplay Between FERC Rate Setting at the Wholesale Level and Allocation to Retail Customers," (with Mariko Geronimo Aydin) presented at *Law Seminars International: Electric Utility Rate Cases*, March 16-17, 2017.

"Capital Structure and Liability Management," *American Gas Association and Edison Electric Institute Public Utility Accounting Course*, August 2015-2017.

"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2013-2017.

"Alternative Regulation and Rate Making Approaches for Water Companies," *Society of Depreciation Professionals Annual Conference*, September 2014.

"Capital Investments and Alternative Regulation," *National Association of Water Companies Annual Policy Forum*, December 2013.

"Accounting for Power Plant," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"GAAP / IFRS Convergence," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"International Innovations in Rate of Return Determination," *Society of Utility Financial and Regulatory Analysts' Financial Forum*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Atlanta, May 2012.

"Cost of Capital Working Group Eforum," *Edison Electric Institute webinar*, April 2012.

"Issues Facing the Global Water Utility Industry" Presented to Sensus' Executive Retreat, Raleigh, NC, July 2010.

"Regulatory Issues from GAAP to IFRS," NASUCA *2009 Annual Meeting*, Chicago, November 2009.

"Subprime Mortgage-Related Litigation: What to Look for and Where to Look," *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

"Evaluating Alternative Business / Inventive Models," (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

"Deferred Income Taxes and IRS's NOPR: Who should benefit?" *NASUCA Annual Meeting*, Anaheim, CA, November 2007.

"Discussion of 'Are Performance Measures Other Than Price Important to CEO Incentives?'" *Annual Meeting of the American Accounting Association*, 2000.

"Contracting and Income Smoothing in an Infinite Agency Model: A Computational Approach," (with R.T. Boylan) *Business and Management Assurance Services Conference*, Austin 2000.

TESTIMONY

Direct Testimony on cost of equity for Consolidated Edison of New York submitted to the *New York Public Service Commission*, Docket No. 19-00317, January 2019.

Direct Testimony on cost of capital and capital structure for Northwest Natural Gas Company submitted to the *Washington Utilities and Transportation Commission*, Docket No. 181053, December 2018.

Pre-filed Direct Testimony on cost of capital and capital structure for Anchorage Water Utility and Anchorage Wastewater Utility submitted to the *Regulatory Commission of Alaska*, TA163-122 and TA164-126, December 2018.

Direct Testimony on cost of capital for Portland General Electric Company submitted to the *Oregon Public Utility Commission* on behalf of Portland General Electric Company (with Hager and Liddle), EU 335, February 2018.

Direct Testimony and Rebuttal Testimony on cost of capital for NW Natural submitted to the *Oregon Public Utility Commission* on behalf of NW Natural, UG 344, December 2017, May 2018.

Direct Pre-filed Testimony and Reply Pre-filed Testimony on cost of equity and capital structure for Anchorage Water and Wastewater Utilities before the *Regulatory Commission of Alaska*, TA161-122 and TA162-126, November 2017, September 2018.

Direct Testimony, Rebuttal Testimony, deposition, and hearing appearance on wholesale water rates for Petitioner Cities, *Texas Public Utility Commission*, PUC Docket 46662, SOAH Docket 473-17-4964.WS, November 2017, January, June, July, October 2018.

Affidavit on Lifting the Dividend Restriction for Anchorage Water Utility for AWWU, *Regulatory Commission of Alaska*, U-17-095, November 2017.

Written Evidence, Rebuttal Evidence and Hearing appearance on the Cost of Capital and Capital Structure for the ATCO Utilities and AUI, 2018-2020 Generic Cost of Capital Proceeding, *Alberta Utilities Commission*, October 2017, February – March 2018.

Written Evidence, Rebuttal Evidence, and Hearing Appearance on Regulatory Tax Treatment for the ATCO Utilities and AUI, 201802020 Generic Cost of Capital Proceeding, *Alberta Utilities Commission*, October 2017, February – March 2018.

Affidavit on the Creation of a Regulatory Assets for PRV Rebates for Anchorage Water Utility, submitted to the *Regulatory Commission of Alaska*, U-17-083, August 2017.

Direct and Rebuttal Testimony, Hearing Appearance on Cost of Capital for California-American Water Company for California-American Water submitted to the *California Public Utilities Commission*, Application 17-04-003, April, August, September 2017.

Direct, Rebuttal, Surrebuttal, Supplemental, Supplemental Rebuttal Testimony and Hearing Appearance on the Cost of Capital for Northern Illinois Gas Company submitted to the *Illinois Commerce Commission*, GRM #17-055, March, July, August, September, and November 2017.

Direct and Rebuttal Testimony on Cost of Capital for Portland General Electric Company submitted to the *Oregon Public Utility Commission* on behalf of Portland General Electric Company, Docket No. UE 319, February, July 2017.

Pre-filed Direct and Reply Testimony and Hearing Appearance on Cost of Equity and Capital Structure for Anchorage Municipal Light and Power, *Regulatory Commission of Alaska*, Docket No. TA357-121, December 2016, August and December 2017.

Expert report and Hearing Appearance regarding the Common Equity Ratio for OPG's Regulated Generation for OEB Staff, *Ontario Energy Board*, EB-2016-0152, November 2016, April 2017.

Pre-filed Direct Testimony on Cost of Equity and Capital Structure for Anchorage Municipal Wastewater Utility, *Regulatory Commission of Alaska*, Docket No. 158-126, November 2016.

Expert Report and Reply Expert Report on damages (quantum) in exit arbitration (with Dan Harris), *International Center for the Settlement of Investment Disputes*, October 2016, October 2018.

Direct Testimony on capital structure, embedded cost of debt, and income taxes for Detroit Thermal, Michigan Public Service Commission, Docket No. UE-18131, July 2016.

Direct Testimony on return on equity for Arizona Public Service Company, Arizona Corporation Commission, Docket E-01345A-16-0036, June 2016.

Written evidence, rebuttal evidence and hearing appearance regarding the cost of equity and capital structure for Alberta-based utilities, the Alberta Utilities Commission, Proceeding No. 20622 on behalf of AltaGas Utilities Inc., ENMAX Power Corporation, FortisAlberta Inc., and The ATCO Utilities, February, May and June 2016.

Verified Statement, Verified Reply Statement, and Hearing Appearance regarding the cost of capital methodology to be applied to freight railroads, the *Surface Transportation Board* on behalf of the Association of American Railroads, Docket No. EP 664 (Sub-No. 2), July 2015, September and November 2015.

Direct Testimony on cost of capital submitted to the Oregon Public Utility Commission on behalf of Portland General Electric, Docket No. UE 294, February 2015.

Supplemental Direct Testimony and Reply Testimony on cost of capital submitted to the *Regulatory Commission of Alaska* on behalf of Anchorage Water and Wastewater utilities, Docket U-13-202, September 2014, March 2015.

Expert Report and hearing appearance on specific accrual and cash flow items in a Sales and Purchase Agreement in international arbitration before the *International Chamber of Commerce*. Case No. 19651/TO, July and November 2014. (*Confidential*)

Rebuttal Testimony regarding Cost of Capital before the *Oregon Public Utility Commission* on behalf of Portland General Electric, Docket No. UE 283, July 2014.

Direct Testimony on the rate impact of the pension re-allocation and other items for Upper Peninsula Power Company in connection with the acquisition by BBIP before the *Michigan Public Service Commission* in Docket No. U-17564, March 2014.

Expert Report on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of oil pipeline in arbitration, April 2013. (*Confidential*)

Direct Testimony on the treatment of goodwill before the *Federal Energy Regulatory Commission* on behalf of ITC Holdings Corp and ITC Midwest, LLC in Docket No. PA10-13-000, February 2012.

Direct and Rebuttal Testimony on cost of capital before the *Public Utilities Commission of the State of California* on behalf of California-American Water in Application No. 11-05, May 2011.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Case No. 11-00196-UT, May 2011, November 2011, and December 2011.

Direct Testimony on regulatory assets and FERC accounting before the *Federal Energy Regulatory Commission* on behalf of AWC Companies, EL11-13-000, December 2010.

Expert Report and deposition in Civil Action No. 02-618 (GK/JMF) in the *United States District Court for the District of Columbia*, November 2010, January 2011. (*Confidential*)

Direct Testimony, Rebuttal Testimony, and Rejoinder Testimony on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-10-0448, November 2010, July 2011, and August 2011.

Direct Testimony on the cost of capital before *the New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 09-00156-UT, August 2009.

Direct and Rebuttal Testimony and Hearing Appearance on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-09-0343, July 2009, March 2010 and April 2010.

Rebuttal Expert Report, Deposition and Oral Testimony re. the impact of alternative discount rate assumptions in tax litigation. *United States Court of Federal Claims*, Case No. 06-628 T, January, February, April 2009. (*Confidential*)

Direct Testimony, Rebuttal Testimony and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 08-00134-UT, June 2008 and January 2009.

Direct Testimony on cost of capital and carrying charge on damages, U.S. Department of Energy, *Bonneville Power Administration*, BPA Docket No. WP-07, March 2008.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-08-0227, April 2008, February 2009, March 2009.

Expert Report, Supplemental Expert Report, and Hearing Appearance on the allocation of corporate overhead and damages from lost profit. *The International Centre for the Settlement of Investment Disputes*, Case No. ARB/03/29, February, April, and June 2008 (*Confidential*).

Expert Report on accounting information needed to assess income. *United States District Court* for the District of Maryland (Baltimore Division), Civil No. 1:06cv02046-JFM, June 2007 (*Confidential*)

Expert Report, Rebuttal Expert Report, and Hearing Appearance regarding investing activities, impairment of assets, leases, shareholder' equity under U.S. GAAP and valuation. *International Chamber of Commerce* (ICC), Case No. 14144/CCO, May 2007, August 2007, September 2007. (Joint with Carlos Lapuerta, *Confidential*)

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0491, July 2006, July 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, Supplemental Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0403, June 2006, April 2007, May 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, and Hearing Appearance on cost of capital before *the Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0014, January 2006, October 2006, November 2006.

Expert report, rebuttal expert report, and deposition on behalf of a major oil company regarding the equity method of accounting and classification of debt and equity, *American Arbitration Association*, August 2004 and November 2004. (*Confidential*).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

EXHIBIT SCE-27

EXHIBIT TO THE TESTIMONY OF DR. BENTE VILLADSEN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

Table No. BV-1

Index to Tables for the Testimony of Bente Villadsen

Table BV-2: Sample Selection

Company	Include Based on American Company	Include Based on Bond Rating	Include Based on Dividend Cuts	Include Based on Revenues	Include Based on M&A	Final Sample
ALLETE	Yes	Yes	Yes	Yes	Yes	Yes
Alliant Energy	Yes	Yes	Yes	Yes	Yes	Yes
Amer. Elec. Power	Yes	Yes	Yes	Yes	Yes	Yes
Ameren Corp.	Yes	Yes	Yes	Yes	Yes	Yes
CMS Energy Corp.	Yes	Yes	Yes	Yes	Yes	Yes
DTE Energy	Yes	Yes	Yes	Yes	Yes	Yes
Entergy Corp.	Yes	Yes	Yes	Yes	Yes	Yes
Evergy Inc.	Yes	Yes	Yes	Yes	Yes	Yes
MGE Energy	Yes	Yes	Yes	Yes	Yes	Yes
OGE Energy	Yes	Yes	Yes	Yes	Yes	Yes
Otter Tail Corp.	Yes	Yes	Yes	Yes	Yes	Yes
WEC Energy Group	Yes	Yes	Yes	Yes	Yes	Yes
AVANGRID Inc.	Yes	Yes	Yes	Yes	Yes	Yes
Consol. Edison	Yes	Yes	Yes	Yes	Yes	Yes
Duke Energy	Yes	Yes	Yes	Yes	Yes	Yes
Eversource Energy	Yes	Yes	Yes	Yes	Yes	Yes
Exelon Corp.	Yes	Yes	Yes	Yes	Yes	Yes
FirstEnergy Corp.	Yes	Yes	Yes	Yes	Yes	Yes
NextEra Energy	Yes	Yes	Yes	Yes	Yes	Yes
PPL Corp.	Yes	Yes	Yes	Yes	Yes	Yes
Public Serv. Enterprise	Yes	Yes	Yes	Yes	Yes	Yes
Southern Co.	Yes	Yes	Yes	Yes	Yes	Yes
Unitil Corp.	Yes	Yes	Yes	Yes	Yes	Yes
Edison Int'l	Yes	Yes	Yes	Yes	Yes	Yes
El Paso Electric	Yes	Yes	Yes	Yes	Yes	Yes
Hawaiian Elec.	Yes	Yes	Yes	Yes	Yes	Yes
IDACORP Inc.	Yes	Yes	Yes	Yes	Yes	Yes
NorthWestern Corp.	Yes	Yes	Yes	Yes	Yes	Yes
Pinnacle West Capital	Yes	Yes	Yes	Yes	Yes	Yes
PNM Resources	Yes	Yes	Yes	Yes	Yes	Yes
Portland General	Yes	Yes	Yes	Yes	Yes	Yes
Sempra Energy	Yes	Yes	Yes	Yes	Yes	Yes
Xcel Energy Inc.	Yes	Yes	Yes	Yes	Yes	Yes
CenterPoint Energy	Yes	Yes	Yes	No	Yes	No
Fortis Inc.	Yes	#N/A	Yes	Yes	No	#N/A
Vectren Corp.	Yes	Yes	No	No	Yes	No
Dominion Energy	Yes	Yes	Yes	No	Yes	No
Summer Energy Holdings Inc	Yes	No	Yes	Yes	No	No
Avista Corp.	Yes	Yes	Yes	No	Yes	No
Black Hills	Yes	Yes	Yes	No	Yes	No
PG&E Corp.	Yes	No	Yes	Yes	Yes	No

Sample Selection Criteria:
Company is publicly traded and has operations in the U.S.
Company has Bloomberg data.
Company has over $300MM in revenue in past year.
Company has maintained at least a BBB- rating over the last 6 months.
Company has no dividend cuts in last 6 months.
Company has no mergers or acquisitions which cumulatively exceed 30% of beginning of year market capitalization in the past 6 months AND
no pending mergers or acquisitions which cumulatively exceed 30% of beginning of year market capitalization in the past 3 years.
Company is not being double counted.

Table No. BV-3

Electric Utility

Summary of Cost of Equity Estimates using IBES Growth Forecast

Company	S&P Bond Rating	Moody's Bond Rating	Dividend Yield	Adjusted Dividend Yield	GDP Growth Forecast	IBES Long Term Growth Rate Forecast	Combined Growth Rate	Implied Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
ALLETE	BBB+	WR	2.94%	N/A	4.24%	N/A	N/A	-
Alliant Energy	A-	WR	3.13%	3.25%	4.24%	7.25%	6.25%	9.49%
Amer. Elec. Power	A-	Baa1	3.49%	3.59%	4.24%	5.74%	5.24%	8.83%
Ameren Corp.	BBB+	WR	2.84%	2.95%	4.24%	7.70%	6.55%	9.49%
CMS Energy Corp.	BBB+	Baa1	2.90%	3.01%	4.24%	7.00%	6.08%	9.09%
DTE Energy	BBB+	Baa1	3.21%	3.30%	4.24%	5.49%	5.07%	8.37%
Entergy Corp.	BBB+	Baa2	4.27%	4.19%	4.24%	-3.77%	-1.10%	~~3.09%~~
Evergy Inc.	A-	Baa2	3.28%	3.43%	4.24%	9.20%	7.55%	10.98%
MGE Energy	AA-	NA	2.12%	N/A	4.24%	N/A	N/A	-
OGE Energy	BBB+	WR	3.74%	3.70%	4.24%	-2.25%	-0.09%	~~3.61%~~
Otter Tail Corp.	BBB	WR	2.80%	N/A	4.24%	N/A	N/A	-
WEC Energy Group	A-	Baa1	3.20%	3.28%	4.24%	4.70%	4.55%	7.83%
AVANGRID Inc.	BBB+	NA	3.57%	3.73%	4.24%	9.20%	7.55%	11.28%
Consol. Edison	A-	Baa1	3.68%	3.74%	4.24%	2.90%	3.34%	7.08%
Duke Energy	A-	Baa1	4.44%	4.54%	4.24%	4.41%	4.35%	8.89%
Eversource Energy	A+	Baa1	3.16%	3.25%	4.24%	5.83%	5.30%	8.55%
Exelon Corp.	BBB+	Baa2	3.11%	3.25%	4.24%	8.77%	7.26%	10.51%
FirstEnergy Corp.	BBB	Baa3	3.84%	3.72%	4.24%	-6.61%	-2.99%	~~0.72%~~
NextEra Energy	A-	NA	2.57%	2.67%	4.24%	7.45%	6.38%	9.05%
PPL Corp.	A-	NA	5.49%	5.59%	4.24%	3.59%	3.81%	9.39%
Public Serv. Enterprise	BBB+	Baa1	3.40%	3.52%	4.24%	7.21%	6.22%	9.74%
Southern Co.	A-	Baa2	5.29%	5.33%	4.24%	1.68%	2.53%	7.86%
Unitil Corp.	BBB+	NA	2.92%	2.98%	4.24%	3.70%	3.88%	6.86%
Edison Int'l	BBB	Baa3	3.92%	3.99%	4.24%	3.75%	3.91%	7.90%
El Paso Electric	BBB	Baa1	2.55%	2.61%	4.24%	5.10%	4.81%	7.43%
Hawaiian Elec.	BBB-	WR	3.42%	3.55%	4.24%	7.80%	6.61%	10.16%
IDACORP Inc.	BBB	Baa1	2.53%	2.56%	4.24%	2.60%	3.15%	~~5.71%~~
NorthWestern Corp.	BBB	Baa2	3.65%	3.69%	4.24%	2.59%	3.14%	6.83%
Pinnacle West Capital	A-	WR	3.47%	3.54%	4.24%	4.16%	4.19%	7.73%
PNM Resources	BBB+	Baa3	2.66%	2.72%	4.24%	4.10%	4.15%	6.86%
Portland General	BBB+	WR	3.13%	3.21%	4.24%	5.05%	4.78%	7.99%
Sempra Energy	BBB+	Baa1	3.13%	3.27%	4.24%	8.69%	7.21%	10.48%
Xcel Energy Inc.	A-	A3	3.10%	3.20%	4.24%	6.60%	5.81%	9.01%
Minimum								**6.83%**
Maximum								11.28%
Median								8.86%
Midpoint								9.06%
Upper End of FERC ZOR								**11.28%**
Upper Midpoint								10.17%

Sources and Notes:
[1], [2]: Bloomberg as of January 31, 2019.
[3]: See Table No. BV-4.
[4] = [3] x (1 + 0.5 x [6])
[5]: See Table No. BV-7.
[6]: See Table No. BV-5.
[7] = ((1/3) x [5]) + ((2/3) x [6])
[8]: [4] + [7], excluding companies that did not meet all sample selection criteria.
* Companies are excluded for (i) the low spread between cost of equity and cost of debt; and/or (ii) negative long-term IBES growth rate.

Table No. BV-4

Electric Utility Sample

Calculation of Dividend Yields

Company	Average Monthly Stock Price as of Aug 31, 2018 [1]	Average Monthly Stock Price as of Sep 30, 2018 [2]	Average Monthly Stock Price as of Oct 31, 2018 [3]	Average Monthly Stock Price as of Nov 30, 2018 [4]	Average Monthly Stock Price as of Dec 31, 2018 [5]	Average Monthly Stock Price as of Jan 31, 2019 [6]	Annualized Monthly Dividend as of Aug 31, 2018 [7]	Annualized Monthly Dividend as of Sep 30, 2018 [8]	Annualized Monthly Dividend as of Oct 31, 2018 [9]	Annualized Monthly Dividend as of Nov 30, 2018 [10]	Annualized Monthly Dividend as of Dec 31, 2018 [11]	Annualized Monthly Dividend as of Jan 31, 2019 [12]	Dividend Yield as of Aug 31, 2018 [13]	Dividend Yield as of Sep 30, 2018 [14]	Dividend Yield as of Oct 31, 2018 [15]	Dividend Yield as of Nov 30, 2018 [16]	Dividend Yield as of Dec 31, 2018 [17]	Dividend Yield as of Jan 31, 2019 [18]	Average Dividend Yield [19]
ALLETE	$76.95	$75.36	$76.05	$77.17	$77.62	$74.77	$2.24	$2.24	$2.24	$2.24	$2.24	$2.24	2.91%	2.97%	2.95%	2.90%	2.89%	3.00%	2.94%
Alliant Energy	$42.62	$42.96	$43.36	$44.14	$43.63	$42.65	$1.34	$1.34	$1.34	$1.34	$1.34	$1.42	3.14%	3.12%	3.09%	3.04%	3.07%	3.33%	3.13%
Amer. Elec. Power	$71.11	$71.33	$72.68	$75.27	$76.79	$75.93	$2.48	$2.48	$2.48	$2.68	$2.68	$2.68	3.49%	3.48%	3.41%	3.56%	3.49%	3.53%	3.49%
Ameren Corp.	$62.94	$64.08	$64.97	$67.00	$66.73	$66.38	$1.83	$1.83	$1.83	$1.83	$1.90	$1.90	2.91%	2.86%	2.82%	2.73%	2.85%	2.86%	2.84%
CMS Energy Corp.	$48.65	$49.26	$50.02	$50.09	$50.73	$50.17	$1.43	$1.43	$1.43	$1.43	$1.43	$1.53	2.94%	2.90%	2.86%	2.86%	2.82%	3.05%	2.90%
DTE Energy	$110.19	$110.36	$112.81	$115.71	$113.99	$112.83	$3.53	$3.53	$3.53	$3.53	$3.78	$3.78	3.20%	3.20%	3.13%	3.05%	3.32%	3.35%	3.21%
Entergy Corp.	$83.16	$82.40	$82.78	$84.96	$86.43	$86.36	$3.56	$3.56	$3.56	$3.64	$3.64	$3.64	4.28%	4.32%	4.30%	4.28%	4.21%	4.21%	4.27%
Evergy Inc.	$56.59	$56.74	$55.98	$58.30	$58.09	$56.49	$1.84	$1.84	$1.84	$1.90	$1.90	$1.90	3.25%	3.24%	3.29%	3.26%	3.27%	3.36%	3.28%
MGE Energy	$65.21	$65.25	$63.48	$63.27	$62.80	$61.45	$1.35	$1.35	$1.35	$1.35	$1.35	$1.35	2.07%	2.07%	2.13%	2.13%	2.15%	2.20%	2.12%
OGE Energy	$36.63	$36.52	$37.02	$37.76	$39.74	$39.62	$1.33	$1.33	$1.46	$1.46	$1.46	$1.46	3.63%	3.64%	3.94%	3.87%	3.67%	3.69%	3.74%
Otter Tail Corp.	$48.55	$48.10	$46.78	$46.68	$49.07	$47.64	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	2.76%	2.79%	2.86%	2.87%	2.73%	2.81%	2.80%
WEC Energy Group	$66.70	$67.24	$69.12	$69.55	$71.11	$70.36	$2.21	$2.21	$2.21	$2.21	$2.21	$2.21	3.31%	3.29%	3.20%	3.18%	3.11%	3.14%	3.20%
AVANGRID Inc.	$50.11	$48.82	$47.68	$49.02	$50.76	$48.84	$1.73	$1.76	$1.76	$1.76	$1.76	$1.76	3.45%	3.61%	3.69%	3.59%	3.47%	3.60%	3.57%
Consol. Edison	$79.31	$77.93	$76.91	$77.16	$79.09	$75.64	$2.86	$2.86	$2.86	$2.86	$2.86	$2.86	3.61%	3.67%	3.72%	3.71%	3.62%	3.78%	3.68%
Duke Energy	$81.11	$80.89	$81.80	$85.06	$87.06	$85.47	$3.71	$3.71	$3.71	$3.71	$3.71	$3.71	4.57%	4.59%	4.54%	4.36%	4.26%	4.34%	4.44%
Eversource Energy	$61.42	$62.02	$62.93	$64.98	$66.57	$66.46	$2.02	$2.02	$2.02	$2.02	$2.02	$2.02	3.29%	3.26%	3.21%	3.11%	3.03%	3.04%	3.16%
Exelon Corp.	$43.39	$43.52	$43.65	$44.74	$45.25	$45.72	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	3.18%	3.17%	3.16%	3.08%	3.05%	3.02%	3.11%
FirstEnergy Corp.	$36.56	$37.12	$37.67	$37.96	$37.61	$37.86	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	3.94%	3.88%	3.82%	3.79%	3.83%	3.80%	3.84%
NextEra Energy	$170.55	$169.53	$171.51	$175.20	$174.49	$174.77	$4.44	$4.44	$4.44	$4.44	$4.44	$4.44	2.60%	2.62%	2.59%	2.53%	2.54%	2.54%	2.57%
PPL Corp.	$29.19	$29.72	$30.24	$31.35	$29.37	$29.59	$1.64	$1.64	$1.64	$1.64	$1.64	$1.64	5.62%	5.52%	5.42%	5.23%	5.58%	5.54%	5.49%
Public Serv. Enterprise	$52.18	$52.25	$54.14	$54.14	$52.78	$52.33	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	3.45%	3.45%	3.33%	3.33%	3.41%	3.44%	3.40%
Southern Co.	$46.53	$44.28	$44.42	$46.01	$45.24	$45.97	$2.40	$2.40	$2.40	$2.40	$2.40	$2.40	5.16%	5.42%	5.40%	5.22%	5.31%	5.22%	5.29%
Unitil Corp.	$50.27	$50.91	$49.19	$48.84	$50.62	$50.08	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	2.90%	2.87%	2.97%	2.99%	2.88%	2.92%	2.92%
Edison Int'l	$67.76	$67.83	$68.98	$57.82	$56.79	$56.42	$2.42	$2.42	$2.42	$2.42	$2.45	$2.45	3.57%	3.57%	3.51%	4.19%	4.31%	4.34%	3.92%
El Paso Electric	$62.65	$59.96	$58.09	$56.86	$52.86	$50.31	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	2.30%	2.40%	2.48%	2.53%	2.72%	2.86%	2.55%
Hawaiian Elec.	$35.10	$35.55	$36.29	$37.48	$37.25	$36.15	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	3.53%	3.49%	3.42%	3.31%	3.33%	3.43%	3.42%
IDACORP Inc.	$95.66	$99.15	$97.42	$97.24	$96.18	$93.50	$2.36	$2.36	$2.36	$2.52	$2.52	$2.52	2.47%	2.38%	2.42%	2.59%	2.62%	2.70%	2.53%
NorthWestern Corp.	$60.10	$58.95	$59.21	$61.55	$61.51	$60.72	$2.20	$2.20	$2.20	$2.20	$2.20	$2.20	3.66%	3.73%	3.72%	3.57%	3.58%	3.62%	3.65%
Pinnacle West Capital	$80.55	$79.16	$82.41	$85.79	$87.89	$85.03	$2.78	$2.78	$2.95	$2.95	$2.95	$2.95	3.45%	3.51%	3.58%	3.44%	3.36%	3.47%	3.47%
PNM Resources	$39.60	$39.45	$39.25	$40.48	$42.43	$41.46	$1.06	$1.06	$1.06	$1.06	$1.06	$1.16	2.68%	2.69%	2.70%	2.62%	2.50%	2.80%	2.66%
Portland General	$45.97	$45.99	$45.74	$46.81	$47.07	$46.26	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	3.15%	3.15%	3.17%	3.10%	3.08%	3.13%	3.13%
Sempra Energy	$115.73	$119.11	$113.85	$113.72	$112.00	$111.63	$3.58	$3.58	$3.58	$3.58	$3.58	$3.58	3.09%	3.01%	3.14%	3.15%	3.20%	3.21%	3.13%
Xcel Energy Inc.	$47.30	$47.75	$48.52	$49.97	$51.13	$50.14	$1.52	$1.52	$1.52	$1.52	$1.52	$1.52	3.21%	3.18%	3.13%	3.04%	2.97%	3.03%	3.10%

Sources and Notes:
[1] - [6]: Average of Intraday High Low Prices, Monthly.
[7] - [12]: Bloomberg dividend data, annualized.
[13] - [18]: Dividend yield = Annualized monthly dividends in [7] - [12] divided by corresponding monthly average price from columns [1] - [6].
[19]: ([13] + [14] + [15] + [16] + [17] + [18]) / 6.

Table No. BV-5

Electric Utility Sample

LT EPS Growth Rate Forecast

Company	IBES Long Term Growth Rate Forecast	Number of Analyst Estimates
	[1]	[2]
ALLETE	N/A	N/A
Alliant Energy	7.25%	2
Amer. Elec. Power	5.74%	2
Ameren Corp.	7.70%	2
CMS Energy Corp.	7.00%	4
DTE Energy	5.49%	4
Entergy Corp.	-3.77%	2
Evergy Inc.	9.20%	1
MGE Energy	N/A	N/A
OGE Energy	-2.25%	2
Otter Tail Corp.	N/A	N/A
WEC Energy Group	4.70%	3
AVANGRID Inc.	9.20%	1
Consol. Edison	2.90%	4
Duke Energy	4.41%	2
Eversource Energy	5.83%	4
Exelon Corp.	8.77%	3
FirstEnergy Corp.	-6.61%	2
NextEra Energy	7.45%	4
PPL Corp.	3.59%	1
Public Serv. Enterprise	7.21%	2
Southern Co.	1.68%	3
Unitil Corp.	3.70%	1
Edison Int'l	3.75%	4
El Paso Electric	5.10%	1
Hawaiian Elec.	7.80%	1
IDACORP Inc.	2.60%	1
NorthWestern Corp.	2.59%	2
Pinnacle West Capital	4.16%	3
PNM Resources	4.10%	1
Portland General	5.05%	2
Sempra Energy	8.69%	2
Xcel Energy Inc.	6.60%	2

Sources and Notes:
[1]&[2]: Long-term (i.e. 5 year) IBES estimates from Thomson Reuters.

Table No. BV-6
Electric Utility Sample
Bloomberg Bond Yields

Month Ending	Public Utility Bond Rating A Yield	Public Utility Bond Rating BBB+ Yield	Public Utility Bond Rating BBB Yield	Public Utility Bond Rating BBB- Yield
8/31/2018	4.21	4.49	4.60	4.80
9/30/2018	4.31	4.59	4.76	4.97
10/31/2018	4.48	4.75	4.98	5.14
11/30/2018	4.56	4.84	5.01	5.27
12/31/2018	4.40	4.71	4.85	5.18
1/31/2019	4.36	4.65	4.81	5.11
Average Yield	4.39	4.67	4.83	5.08

Sources and Notes:
Bloomberg as of January 31, 2019.

Table No. BV-7
Electric Utility Sample
Long Term GDP Growth Rate Forecasts

[1]	**SSA - 2018**		**2020**		**2050**		**CAGR**
	GDP in dollars (billions)	$	22,288	$	81,536		4.42% [a]
[2]	**SSA - 2018**		**2050**		**2090**		
	GDP in dollars (billions)	$	81,536	$	444,282		4.33% [b]
[3]	**SSA - 2018**		**2020**		**2090**		
	GDP in dollars (billions)	$	22,288	$	444,282		4.37% [c]
[4]	**EIA**		**2017**		**2050**		
	Real GDP Forecast	$	17,096	$	32,006	1.92%	
	GDP Chain-Type Price Index (2009=1.000)		1.13		2.42	2.32%	
	Nominal GDP Forecast	$	19,391	$	77,412		4.28% [d]
[5]	**EIA (2018 - 2050)**						
	Real GDP Growth (%)					1.89%	
	GDP Chain-Type Price Index Growth (%)					2.33%	
	Nominal GDP Growth (%)						4.27% [e]
[6]	**EIA (2020 - 2050)**		**2020**		**2050**		
	Real GDP Forecast	$	18,487	$	32,006	1.85%	
	GDP Chain-Type Price Index (2009=1.000)		1.22		2.42	2.31%	
		$	22,514	$	77,412		4.20% [f]
[7]	**EIA, estimated 2050 (2020 - 2050)**		**2020**		**2050**		
	Real GDP Forecast, using historical GDP growth rate (1929-2017)	$	18,487	$	47,846	3.22%	
	GDP Chain-Type Price Index (2009=1.000)		1.218		2.419	2.31%	
		$	22,514	$	115,721		5.61% [g]
[8]	**Blue Chip Value Indicators (2025 - 2029)**						
	Nominal GDP Growth Forecast (%)					4.10%	4.10% [h]
	UPDATED AVERAGE						
	Average (SSA, EIA, Blue Chip)						4.22% =average[c,f,h]
	Average (SSA, EIA, Blue Chip)						**4.24%** =average[a,f,h]

Sources and Notes:

[1]-[3]: Social Security Administration: The 2018 OASDI Trustees Report, Table VI.G4.-OASDI and HI Annual and Summarized Income, Cost, and Balance as a Percentage of GDP, Calander years 2018-95, Intermediate Assumptions.

[4] - [7]: Energy Information Administration Annual Energy Outlook 2019 Release with Projections to 2050 Released Jan. 2019, Table A20. Macroeconomic Indicators. Nominal GDP=(Real GDP)*(GDP Chain-Type Price Index).

[7]: 2050 GDP forecasted using annualized GDP growth rate from 1929 - 2017 from U.S. Bureau of Economic Analysis (BEA). (Accessed February 2019).

[8]: Blue Chip Economic Indicators, Vol. 43, No. 3. "Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead." October 2018.

Table No. BV-8
Electric Utility Sample
CAPM ROE Estimates

Company	Div Yield	Proj. Growth	Cost of Equity	RFR	Risk Premium	Beta	Unadjusted Ke	Market Cap ($Million)	Size Adjustment	Implied Cost of Equity
	[1]	[2]	[3] = [2]+[3]	[4]	[5] = [3]-[4]	[6]	[7] = [4]+[5]*[6]	[8]	[9]	[10] = [7] + [9]
ALLETE	2.58%	10.78%	13.37%	3.70%	9.67%	0.65	9.98%	$3,955	0.98%	10.96%
Alliant Energy	2.58%	10.78%	13.37%	3.70%	9.67%	0.60	9.50%	$10,492	0.89%	10.39%
Amer. Elec. Power	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$39,014	-0.35%	8.67%
Ameren Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$16,933	0.61%	9.63%
AVANGRID Inc.	2.58%	10.78%	13.37%	3.70%	9.67%	0.30	6.60%	$15,410	0.61%	7.21%
CMS Energy Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$14,771	0.61%	9.63%
Consol. Edison	2.58%	10.78%	13.37%	3.70%	9.67%	0.40	7.57%	$24,182	0.61%	8.18%
DTE Energy	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$21,422	0.61%	9.63%
Duke Energy	2.58%	10.78%	13.37%	3.70%	9.67%	0.50	8.53%	$62,587	-0.35%	8.18%
Edison Int'l	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$18,562	0.61%	9.63%
El Paso Electric	2.58%	10.78%	13.37%	3.70%	9.67%	0.65	9.98%	$2,129	1.66%	11.64%
Entergy Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.60	9.50%	$16,155	0.61%	10.11%
Evergy Inc.	2.58%	10.78%	13.37%	3.70%	9.67%	N/A	N/A	$14,956	0.61%	N/A
Eversource Energy	2.58%	10.78%	13.37%	3.70%	9.67%	0.60	9.50%	$21,995	0.61%	10.11%
Exelon Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.65	9.98%	$46,184	-0.35%	9.63%
FirstEnergy Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.60	9.50%	$20,049	0.61%	10.11%
Hawaiian Elec.	2.58%	10.78%	13.37%	3.70%	9.67%	0.60	9.50%	$4,049	0.98%	10.48%
IDACORP Inc.	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$4,913	0.98%	10.00%
MGE Energy	2.58%	10.78%	13.37%	3.70%	9.67%	0.60	9.50%	$2,230	1.66%	11.16%
NextEra Energy	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$85,543	-0.35%	8.67%
NorthWestern Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$3,444	1.51%	10.53%
OGE Energy	2.58%	10.78%	13.37%	3.70%	9.67%	0.85	11.92%	$8,179	0.89%	12.81%
Otter Tail Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.75	10.95%	$1,922	1.66%	12.61%
Pinnacle West Capital	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$9,869	0.89%	9.91%
PNM Resources	2.58%	10.78%	13.37%	3.70%	9.67%	0.65	9.98%	$3,393	1.51%	11.49%
Portland General	2.58%	10.78%	13.37%	3.70%	9.67%	0.60	9.50%	$4,312	0.98%	10.48%
PPL Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.70	10.47%	$22,541	0.61%	11.08%
Public Serv. Enterprise	2.58%	10.78%	13.37%	3.70%	9.67%	0.60	9.50%	$27,493	-0.35%	9.15%
Sempra Energy	2.58%	10.78%	13.37%	3.70%	9.67%	0.75	10.95%	$32,053	-0.35%	10.60%
Southern Co.	2.58%	10.78%	13.37%	3.70%	9.67%	0.50	8.53%	$48,551	-0.35%	8.18%
Unitil Corp.	2.58%	10.78%	13.37%	3.70%	9.67%	0.55	9.02%	$780	2.08%	11.10%
WEC Energy Group	2.58%	10.78%	13.37%	3.70%	9.67%	0.50	8.53%	$23,043	0.61%	9.14%
Xcel Energy Inc.	2.58%	10.78%	13.37%	3.70%	9.67%	0.50	8.53%	$26,876	-0.35%	8.18%
Minimum										**7.21%**
Maximum										12.81%
Median										10.05%
Midpoint										10.01%
Upper end of ZOR										**12.81%**
Upper Midpoint										11.41%

Sources and Notes:
[1]: Value Line Investment Analyzer as of 01/31/2019, weighted average dividend yield for dividend paying firms in S&P 500 Index.
[2]: Weighted average of earnings growth rates from IBES for dividend-paying stocks in the S&P 500, accessed 1/31/2019.
[4]: Forecast for 2020 10 Year Treasury Bond Yield + 50bps Spread, January 2019 Blue Chip Economic Indicators.
[6]&[8]: Value Line Investment Analyzer as of 01/31/2019. Evergy Inc. market cap is from Bloomberg, as of 12/31/2018.
[9]: Duff&Phelps 2017 Valuation Handbook U.S. Guide to Cost of Capital, 7-10 and 7-11.

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions) [1]	Annual Dividend Yield [2]	Projected Growth Rate [3]	Projected Growth Rate Greater Than 0% and Less Than 20% [4]	Implied Cost of Equity Before Additional Screens [5] =[2]+[4]	Projected Growth Rate Accounting for Low-End Outlier Test [5]
3M Company	$116,632	2.73%	8.07%	8.07%	10.80%	8.07%
Abbott Labs.	$128,177	1.77%	11.06%	11.06%	12.83%	11.06%
AbbVie Inc.	$120,769	5.32%	7.76%	7.76%	13.08%	7.76%
ABIOMED Inc.	$15,812	0.00%	N/A	N/A	0.00%	N/A
Accenture Plc	$97,969	1.98%	8.69%	8.69%	10.67%	8.69%
Activision Blizzard	$36,044	0.83%	9.14%	9.14%	9.96%	9.14%
Adobe Systems	$120,853	0.00%	N/A	N/A	0.00%	N/A
Advance Auto Parts	$11,605	0.15%	20.48%	N/A	0.15%	N/A
Advanced Micro Dev.	$24,386	0.00%	N/A	N/A	0.00%	N/A
AES Corp.	$10,855	3.30%	10.30%	10.30%	13.60%	10.30%
Affiliated Managers	$6,140	1.52%	2.64%	2.64%	4.17%	N/A
Aflac Inc.	$36,401	2.34%	9.14%	9.14%	11.48%	9.14%
Agilent Technologies	$24,260	0.87%	10.51%	10.51%	11.38%	10.51%
Air Products & Chem.	$36,105	2.80%	11.04%	11.04%	13.84%	11.04%
Akamai Technologies	$11,060	0.00%	N/A	N/A	0.00%	N/A
Alaska Air Group	$7,889	2.18%	12.17%	12.17%	14.34%	12.17%
Albemarle Corp.	$8,573	1.65%	12.49%	12.49%	14.14%	12.49%
Alexandria Real Estate	$13,143	2.97%	8.40%	8.40%	11.37%	8.40%
Alexion Pharmac.	$27,432	0.00%	N/A	N/A	0.00%	N/A
Align Techn.	$20,254	0.00%	N/A	N/A	0.00%	N/A
Allegion plc	$8,161	0.97%	11.18%	11.18%	12.15%	11.18%
Allergan plc	$48,550	2.05%	5.21%	5.21%	7.27%	5.21%
Alliance Data Sys.	$9,696	1.26%	12.43%	12.43%	13.69%	12.43%
Alliant Energy	$10,492	3.22%	7.25%	7.25%	10.47%	7.25%
Allstate Corp.	$30,315	2.07%	14.32%	14.32%	16.40%	14.32%
Alphabet Inc.	$776,946	0.00%	N/A	N/A	0.00%	N/A
Alphabet Inc. 'A'	$783,559	0.00%	N/A	N/A	0.00%	N/A
Altria Group	$92,781	6.50%	8.40%	8.40%	14.90%	8.40%
Amazon.com	$840,459	0.00%	N/A	N/A	0.00%	N/A
Amer. Airlines	$16,474	1.11%	18.43%	18.43%	19.53%	18.43%
Amer. Elec. Power	$39,014	3.44%	5.74%	5.74%	9.17%	5.74%
Amer. Express	$87,706	1.60%	17.33%	17.33%	18.93%	17.33%
Amer. Int'l Group	$38,243	2.92%	26.58%	N/A	2.92%	N/A
Amer. Tower 'A'	$76,184	2.02%	8.05%	8.05%	10.07%	8.05%
Amer. Water Works	$17,278	2.04%	8.20%	8.20%	10.24%	8.20%
Ameren Corp.	$16,933	2.80%	7.70%	7.70%	10.50%	7.70%
Ameriprise Fin'l	$17,701	2.84%	18.84%	18.84%	21.67%	18.84%
AmerisourceBergen	$18,083	1.91%	9.04%	9.04%	10.95%	9.04%
AMETEK Inc.	$16,921	0.76%	14.90%	14.90%	15.66%	14.90%
Amgen	$119,844	3.10%	5.00%	5.00%	8.10%	5.00%
Amphenol Corp.	$26,490	1.05%	8.70%	8.70%	9.75%	8.70%
Anadarko Petroleum	$23,376	2.48%		N/A	2.48%	N/A
Analog Devices	$36,594	1.91%	9.34%	9.34%	11.25%	9.34%
ANSYS Inc.	$13,809	0.00%	N/A	N/A	0.00%	N/A
Anthem Inc.	$78,456	1.06%	15.26%	15.26%	16.32%	15.26%
Aon plc	$37,683	0.96%	15.22%	15.22%	16.18%	15.22%
Apache Corp.	$12,523	3.06%	76.32%	N/A	3.06%	N/A
Apartment Investment	$8,166	3.10%	7.10%	7.10%	10.20%	7.10%
Apple Inc.	$791,420	1.93%	13.00%	13.00%	14.93%	13.00%
Applied Materials	$37,790	2.04%	10.77%	10.77%	12.81%	10.77%
Aptiv PLC	$20,898	1.13%	10.80%	10.80%	11.93%	10.80%
Archer Daniels Midl'd	$25,144	2.99%		N/A	2.99%	N/A
Arconic Inc.	$9,095	1.30%		N/A	1.30%	N/A
Arista Networks	$16,193	0.00%	N/A	N/A	0.00%	N/A
Assurant Inc.	$6,012	2.47%		N/A	2.47%	N/A
AT&T Inc.	$218,545	6.80%	6.25%	6.25%	13.05%	6.25%
Autodesk Inc.	$32,238	0.00%	N/A	N/A	0.00%	N/A
Automatic Data Proc.	$61,278	2.37%	16.36%	16.36%	18.73%	16.36%
AutoZone Inc.	$21,367	0.00%	N/A	N/A	0.00%	N/A

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions) [1]	Annual Dividend Yield [2]	Projected Growth Rate [3]	Projected Growth Rate Greater Than 0% and Less Than 20% [4]	Implied Cost of Equity Before Additional Screens [5] =[2]+[4]	Projected Growth Rate Accounting for Low-End Outlier Test [5]
AvalonBay Communities	$26,641	3.21%		N/A	3.21%	N/A
Avery Dennison	$9,089	2.11%	11.06%	11.06%	13.16%	11.06%
Baker Hughes a GE co.	$9,711	2.96%		N/A	2.96%	N/A
Ball Corp.	$17,811	0.77%	11.36%	11.36%	12.13%	11.36%
Bank of America	$280,665	2.11%	20.69%	N/A	2.11%	N/A
Bank of New York Mellon	$51,733	2.13%	9.43%	9.43%	11.56%	9.43%
Baxter Int'l Inc.	$38,658	1.05%	12.32%	12.32%	13.38%	12.32%
BB&T Corp.	$37,606	3.31%	3.97%	3.97%	7.28%	3.97%
Becton Dickinson	$66,911	1.26%	11.99%	11.99%	13.25%	11.99%
Berkshire Hathaway 'B'	$0	0.00%	N/A	N/A	0.00%	N/A
Best Buy Co.	$16,113	3.76%	16.27%	16.27%	20.03%	16.27%
Biogen	$67,251	0.00%	N/A	N/A	0.00%	N/A
BlackRock Inc.	$65,931	3.17%	8.34%	8.34%	11.51%	8.34%
Block (H&R)	$4,848	4.29%	10.00%	10.00%	14.29%	10.00%
Boeing	$219,417	2.12%	23.58%	N/A	2.12%	N/A
Booking Holdings	$85,457	0.00%	N/A	N/A	0.00%	N/A
BorgWarner	$8,518	1.65%	9.08%	9.08%	10.73%	9.08%
Boston Properties	$20,351	2.97%	6.00%	6.00%	8.97%	6.00%
Boston Scientific	$52,788	0.00%	N/A	N/A	0.00%	N/A
Brighthouse Financial Inc	$4,436	0.00%	N/A	N/A	0.00%	N/A
Bristol-Myers Squibb	$80,582	3.29%	8.37%	8.37%	11.66%	8.37%
Broadcom Inc.	$110,787	3.97%	15.28%	15.28%	19.26%	15.28%
Broadridge Fin'l	$11,777	1.88%	10.00%	10.00%	11.88%	10.00%
Brown-Forman 'B'	$22,614	1.39%		N/A	1.39%	N/A
C.H. Robinson	$11,974	2.28%	7.59%	7.59%	9.87%	7.59%
Cabot Oil & Gas 'A'	$10,829	1.12%	44.44%	N/A	1.12%	N/A
CA Inc.		N/A	N/A	N/A	0.00%	N/A
Campbell Soup	$11,444	4.00%	-1.35%	N/A	4.00%	N/A
Capital One Fin'l	$38,172	1.98%	6.10%	6.10%	8.08%	6.10%
Capri Holdings Ltd.	$6,378	0.00%	N/A	N/A	0.00%	N/A
Cardinal Health	$14,991	3.89%	8.90%	8.90%	12.79%	8.90%
CarMax Inc.	$10,098	0.00%	N/A	N/A	0.00%	N/A
Carnival Corp.	$40,306	3.47%	11.75%	11.75%	15.22%	11.75%
Caterpillar Inc.	$78,579	2.63%	25.22%	N/A	2.63%	N/A
Cboe Global Markets	$10,411	1.32%	14.79%	14.79%	16.11%	14.79%
CBRE Group	$15,595	0.00%	N/A	N/A	0.00%	N/A
CBS Corp. 'B'	$18,548	1.45%	17.76%	17.76%	19.21%	17.76%
Celanese Corp.	$12,975	2.43%	11.12%	11.12%	13.55%	11.12%
Celgene Corp.	$61,825	0.00%	N/A	N/A	0.00%	N/A
Centene Corp.	$26,813	0.00%	N/A	N/A	0.00%	N/A
CenterPoint Energy	$13,344	3.73%	10.05%	10.05%	13.79%	10.05%
CenturyLink Inc.	$16,554	14.16%	-7.42%	N/A	14.16%	N/A
Cerner Corp.	$18,089	0.00%	N/A	N/A	0.00%	N/A
CF Industries	$10,120	2.99%		N/A	2.99%	N/A
Charter Communic.	$79,262	0.00%	N/A	N/A	0.00%	N/A
Chevron Corp.	$219,070	3.85%	57.78%	N/A	3.85%	N/A
Chipotle Mex. Grill	$14,719	0.00%	N/A	N/A	0.00%	N/A
Chubb Ltd.	$61,350	2.19%	11.54%	11.54%	13.73%	11.54%
Church & Dwight	$15,895	1.35%	10.59%	10.59%	11.93%	10.59%
Cigna Corp.	$48,661	0.02%	18.11%	18.11%	18.13%	18.11%
Cimarex Energy	$7,203	0.95%	260.33%	N/A	0.95%	N/A
Cincinnati Financial	$13,198	2.60%	7.31%	7.31%	9.91%	7.31%
Cintas Corp.	$19,712	1.09%	16.00%	16.00%	17.09%	16.00%
Cisco Systems	$213,609	2.98%	8.93%	8.93%	11.91%	8.93%
Citigroup Inc.	$157,420	3.11%	11.54%	11.54%	14.65%	11.54%
Citizens Fin'l Group	$16,082	3.74%	16.96%	16.96%	20.70%	16.96%
Citrix Sys.	$13,808	1.35%	9.13%	9.13%	10.48%	9.13%
Clorox Co.	$18,934	2.56%	4.20%	4.20%	6.76%	4.20%
CME Group	$61,950	1.53%	18.79%	18.79%	20.32%	18.79%

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions) [1]	Annual Dividend Yield [2]	Projected Growth Rate [3]	Projected Growth Rate Greater Than 0% and Less Than 20% [4]	Implied Cost of Equity Before Additional Screens [5] =[2]+[4]	Projected Growth Rate Accounting for Low-End Outlier Test [5]
CMS Energy Corp.	$14,771	2.95%	7.00%	7.00%	9.96%	7.00%
Coca-Cola	$204,841	3.41%	6.61%	6.61%	10.02%	6.61%
Cognizant Technology	$40,414	1.14%	10.96%	10.96%	12.10%	10.96%
Colgate-Palmolive	$56,098	2.58%	4.35%	4.35%	6.93%	4.35%
Comcast Corp.	$166,375	2.28%	12.90%	12.90%	15.18%	12.90%
Comerica Inc.	$13,066	3.39%	19.80%	19.80%	23.19%	19.80%
Conagra Brands	$10,509	3.97%	6.30%	6.30%	10.27%	6.30%
Concho Resources	$23,997	0.00%	N/A	N/A	0.00%	N/A
ConocoPhillips	$77,928	1.78%	84.82%	N/A	1.78%	N/A
Consol. Edison	$24,182	3.86%	2.90%	2.90%	6.76%	2.90%
Constellation Brands	$32,971	1.84%	8.63%	8.63%	10.47%	8.63%
Cooper Cos.	$13,687	0.02%	16.00%	16.00%	16.02%	16.00%
Copart Inc.	$11,848	0.00%	N/A	N/A	0.00%	N/A
Corning Inc.	$26,621	2.18%		N/A	2.18%	N/A
Costco Wholesale	$94,554	1.16%	10.54%	10.54%	11.70%	10.54%
Coty Inc.	$5,826	6.63%	7.88%	7.88%	14.51%	7.88%
Crown Castle Int'l	$48,580	3.93%	15.60%	15.60%	19.53%	15.60%
CSX Corp.	$55,478	1.33%	11.68%	11.68%	13.01%	11.68%
Cummins Inc.	$23,611	3.11%	12.27%	12.27%	15.37%	12.27%
CVS Health	$66,796	3.07%	12.35%	12.35%	15.42%	12.35%
Danaher Corp.	$77,733	0.59%	7.30%	7.30%	7.88%	7.30%
Darden Restaurants	$12,960	2.95%	13.23%	13.23%	16.18%	13.23%
DaVita Inc.	$9,317	0.00%	N/A	N/A	0.00%	N/A
Deere & Co.	$52,227	1.86%	19.27%	19.27%	21.12%	19.27%
Delta Air Lines	$33,890	2.80%	14.33%	14.33%	17.14%	14.33%
Dentsply Sirona	$9,334	0.83%	-0.28%	N/A	0.83%	N/A
Devon Energy	$12,608	1.18%	40.32%	N/A	1.18%	N/A
Diamondback Energy	$10,175	0.73%	28.34%	N/A	0.73%	N/A
Digital Realty Trust	$22,261	3.96%		N/A	3.96%	N/A
Discover Fin'l Svcs.	$22,806	2.34%	17.06%	17.06%	19.40%	17.06%
Discovery Communic. 'C'	$13,915	0.00%	N/A	N/A	0.00%	N/A
Discovery Inc.	$14,857	0.00%	N/A	N/A	0.00%	N/A
Dish Network 'A'	$14,344	0.00%	N/A	N/A	0.00%	N/A
Disney (Walt)	$165,942	1.58%	4.75%	4.75%	6.33%	4.75%
Dollar General	$30,345	1.01%	14.03%	14.03%	15.03%	14.03%
Dollar Tree Inc.	$23,043	0.00%	N/A	N/A	0.00%	N/A
Dominion Energy	$46,007	5.19%	6.49%	6.49%	11.67%	6.49%
Dover Corp.	$12,852	2.19%	14.10%	14.10%	16.29%	14.10%
DowDuPont Inc.	$123,442	3.14%	8.15%	8.15%	11.29%	8.15%
DTE Energy	$21,422	3.27%	5.49%	5.49%	8.76%	5.49%
Duke Energy	$62,587	4.32%	4.41%	4.41%	8.72%	4.41%
Duke Realty Corp.	$10,420	2.98%	-12.65%	N/A	2.98%	N/A
DXC Technology	$18,107	1.17%	9.79%	9.79%	10.95%	9.79%
E*Trade Fin'l	$11,981	1.18%	22.53%	N/A	1.18%	N/A
Eastman Chemical	$11,286	3.04%	9.84%	9.84%	12.88%	9.84%
Eaton Corp. plc	$33,047	3.45%	8.79%	8.79%	12.24%	8.79%
eBay Inc.	$32,405	1.63%	10.77%	10.77%	12.40%	10.77%
Ecolab Inc.	$45,691	1.16%	13.37%	13.37%	14.53%	13.37%
Edison Int'l	$18,562	4.35%	3.75%	3.75%	8.10%	3.75%
Edwards Lifesciences	$35,635	0.00%	N/A	N/A	0.00%	N/A
Electronic Arts	$28,041	0.00%	N/A	N/A	0.00%	N/A
Emerson Electric	$41,194	2.96%	8.78%	8.78%	11.74%	8.78%
Entergy Corp.	$16,155	4.12%	-3.77%	N/A	4.12%	N/A
EQT Corp.		N/A	N/A	N/A	0.00%	N/A
Equifax Inc.	$12,907	1.45%	1.71%	1.71%	3.15%	N/A
Equinix Inc.	$31,517	2.62%	10.00%	10.00%	12.62%	10.00%
Equity Residential	$26,703	3.00%		N/A	3.00%	N/A
Essex Property Trust	$17,914	2.83%		N/A	2.83%	N/A
Everest Re Group Ltd.	$8,904	2.56%	39.64%	N/A	2.56%	N/A

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions) [1]	Annual Dividend Yield [2]	Projected Growth Rate [3]	Projected Growth Rate Greater Than 0% and Less Than 20% [4]	Implied Cost of Equity Before Additional Screens [5] =[2]+[4]	Projected Growth Rate Accounting for Low-End Outlier Test [5]
Evergy Inc.	$0	3.39%	5.60%	5.60%	8.99%	5.60%
Eversource Energy	$21,995	3.05%	5.83%	5.83%	8.88%	5.83%
Exelon Corp.	$46,184	3.06%	8.77%	8.77%	11.83%	8.77%
Expedia Group	$17,795	1.05%	15.79%	15.79%	16.84%	15.79%
Expeditors Int'l	$11,959	1.29%	12.20%	12.20%	13.49%	12.20%
Express Scripts		N/A	N/A	N/A	0.00%	N/A
Exxon Mobil Corp.	$310,268	4.40%	16.67%	16.67%	21.07%	16.67%
F5 Networks	$9,692	0.00%	N/A	N/A	0.00%	N/A
Facebook Inc.	$478,900	0.00%	N/A	N/A	0.00%	N/A
Fastenal Co.	$17,356	2.64%		N/A	2.64%	N/A
Federal Rlty. Inv. Trust	$9,690	3.10%		N/A	3.10%	N/A
FedEx Corp.	$46,354	1.45%	9.71%	9.71%	11.16%	9.71%
Fidelity Nat'l Info.	$34,286	1.19%	13.67%	13.67%	14.86%	13.67%
Fifth Third Bancorp	$17,584	3.28%		N/A	3.28%	N/A
First Republic Bank	$15,921	0.73%	10.60%	10.60%	11.33%	10.60%
FirstEnergy Corp.	$20,049	3.92%	-6.61%	N/A	3.92%	N/A
Fiserv Inc.	$33,255	0.00%	N/A	N/A	0.00%	N/A
FleetCor Technologies	$17,890	0.00%	N/A	N/A	0.00%	N/A
FLIR Systems	$6,762	1.40%		N/A	1.40%	N/A
Flowserve Corp.	$5,750	1.73%	19.01%	19.01%	20.73%	19.01%
Fluor Corp.	$5,147	2.31%	35.50%	N/A	2.31%	N/A
FMC Corp.	$10,746	1.86%	26.80%	N/A	1.86%	N/A
Foot Locker	$6,337	2.51%	10.54%	10.54%	13.04%	10.54%
Ford Motor	$35,006	6.88%	3.80%	3.80%	10.68%	3.80%
Fortinet Inc.	$13,040	0.00%	N/A	N/A	0.00%	N/A
Fortive Corp.	$26,232	0.38%	13.75%	13.75%	14.12%	13.75%
Fortune Brands Home	$6,406	1.96%	10.20%	10.20%	12.16%	10.20%
Franklin Resources	$15,145	3.61%	-4.21%	N/A	3.61%	N/A
Freep't-McMoRan Inc.	$16,866	2.09%	1.83%	1.83%	3.91%	N/A
Gallagher (Arthur J.)	$13,724	2.13%	13.75%	13.75%	15.89%	13.75%
Gap (The) Inc.	$9,718	3.88%	9.99%	9.99%	13.87%	9.99%
Garmin Ltd.	$13,062	3.06%	6.98%	6.98%	10.03%	6.98%
Gartner Inc.	$12,352	0.00%	N/A	N/A	0.00%	N/A
Gen'l Dynamics	$50,692	2.20%	11.15%	11.15%	13.35%	11.15%
Gen'l Electric	$88,373	0.39%	2.91%	2.91%	3.31%	N/A
Gen'l Mills	$26,517	4.48%	6.05%	6.05%	10.53%	6.05%
Gen'l Motors	$54,628	4.02%	14.40%	14.40%	18.42%	14.40%
Genuine Parts	$14,650	2.85%		N/A	2.85%	N/A
Gilead Sciences	$90,593	3.25%	-5.80%	N/A	3.25%	N/A
Global Payments	$17,761	0.04%	22.36%	N/A	0.04%	N/A
Goldman Sachs	$73,806	1.63%	6.43%	6.43%	8.06%	6.43%
Goodyear Tire	$4,937	3.14%	2.41%	2.41%	5.55%	N/A
Grainger (W.W.)	$16,636	1.86%	13.70%	13.70%	15.56%	13.70%
Halliburton Co.	$27,471	2.24%	27.00%	N/A	2.24%	N/A
Hanesbrands Inc.	$5,406	3.95%	-1.12%	N/A	3.95%	N/A
Harley-Davidson	$6,002	4.04%	8.50%	8.50%	12.54%	8.50%
Harris Corp.	$18,016	1.78%	18.28%	18.28%	20.06%	18.28%
Hartford Fin'l Svcs.	$16,829	2.55%	19.84%	19.84%	22.39%	19.84%
Hasbro Inc.	$11,475	2.78%	4.05%	4.05%	6.83%	4.05%
HCA Healthcare	$48,115	1.15%	16.30%	16.30%	17.45%	16.30%
HCP Inc.	$14,806	4.87%	4.00%	4.00%	8.87%	4.00%
Helmerich & Payne	$6,100	5.02%		N/A	5.02%	N/A
Henry (Jack) & Assoc.	$10,322	1.10%	11.00%	11.00%	12.10%	11.00%
Hershey Co.	$22,251	2.76%	9.25%	9.25%	12.01%	9.25%
Hess Corp.	$15,998	1.80%	15.00%	15.00%	16.80%	15.00%
Hewlett Packard Ent.	$22,185	2.87%		N/A	2.87%	N/A
Hilton Worldwide Hldgs.	$22,118	0.81%	23.61%	N/A	0.81%	N/A
HollyFrontier Corp.	$9,829	2.45%	41.18%	N/A	2.45%	N/A
Hologic Inc.	$12,071	0.00%	N/A	N/A	0.00%	N/A

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions) [1]	Annual Dividend Yield [2]	Projected Growth Rate [3]	Projected Growth Rate Greater Than 0% and Less Than 20% [4]	Implied Cost of Equity Before Additional Screens [5] =[2]+[4]	Projected Growth Rate Accounting for Low-End Outlier Test [5]
Home Depot	$207,572	2.49%	14.09%	14.09%	16.59%	14.09%
Honeywell Int'l	$106,328	2.27%	6.64%	6.64%	8.91%	6.64%
Hormel Foods	$22,605	2.00%		N/A	2.00%	N/A
Horton D.R.	$14,351	1.58%	9.67%	9.67%	11.24%	9.67%
Host Hotels & Resorts	$13,348	4.60%	5.00%	5.00%	9.60%	5.00%
HP Inc.	$34,367	2.88%	7.50%	7.50%	10.38%	7.50%
Humana Inc.	$42,389	0.67%	15.89%	15.89%	16.56%	15.89%
Hunt (J.B.)	$11,686	0.96%	14.41%	14.41%	15.37%	14.41%
Huntington Bancshs.	$14,055	4.20%	9.00%	9.00%	13.20%	9.00%
Huntington Ingalls	$8,877	1.67%	8.95%	8.95%	10.61%	8.95%
IDEXX Labs.	$18,415	0.00%	N/A	N/A	0.00%	N/A
IHS Markit	$20,631	0.00%	N/A	N/A	0.00%	N/A
Illinois Tool Works	$45,560	2.98%	11.57%	11.57%	14.55%	11.57%
Illumina Inc.	$41,129	0.00%	N/A	N/A	0.00%	N/A
Incyte Corp.	$17,146	0.00%	N/A	N/A	0.00%	N/A
Ingersoll-Rand	$24,575	2.10%	10.86%	10.86%	12.96%	10.86%
Intel Corp.	$215,056	2.59%	10.67%	10.67%	13.26%	10.67%
Intercontinental Exch.	$43,830	1.24%	13.67%	13.67%	14.91%	13.67%
Interpublic Group	$8,898	3.71%	7.50%	7.50%	11.21%	7.50%
Int'l Business Mach.	$122,160	4.86%		N/A	4.86%	N/A
Int'l Flavors & Frag.	$13,004	2.10%	9.50%	9.50%	11.60%	9.50%
Int'l Paper	$19,209	4.32%	11.50%	11.50%	15.82%	11.50%
Intuit Inc.	$56,021	0.88%	14.57%	14.57%	15.44%	14.57%
Intuitive Surgical	$59,800	0.00%	N/A	N/A	0.00%	N/A
Invesco Ltd.	$7,494	6.54%	0.86%	0.86%	7.39%	0.86%
IPG Photonics	$7,230	0.00%	N/A	N/A	0.00%	N/A
IQVIA Holdings	$26,099	0.00%	N/A	N/A	0.00%	N/A
Iron Mountain	$10,647	6.66%	-0.97%	N/A	6.66%	N/A
Jacobs Engineering	$9,193	1.04%	12.12%	12.12%	13.16%	12.12%
Jefferies Fin'l Group	$6,897	2.42%		N/A	2.42%	N/A
Johnson & Johnson	$357,074	2.77%	6.51%	6.51%	9.28%	6.51%
Johnson Ctrls. Int'l plc	$31,238	3.13%		N/A	3.13%	N/A
JPMorgan Chase	$344,180	3.12%	14.09%	14.09%	17.21%	14.09%
Juniper Networks	$8,952	2.94%	12.36%	12.36%	15.31%	12.36%
Kansas City South'n	$10,755	1.36%	13.88%	13.88%	15.24%	13.88%
Kellogg	$20,477	3.85%	3.35%	3.35%	7.20%	3.35%
KeyCorp	$17,035	4.09%	6.80%	6.80%	10.89%	6.80%
Keysight Technologies	$13,864	0.00%	N/A	N/A	0.00%	N/A
Kimberly-Clark	$38,571	3.69%	4.17%	4.17%	7.86%	4.17%
Kimco Realty	$7,240	6.64%	6.60%	6.60%	13.24%	6.60%
Kinder Morgan Inc.	$39,920	4.36%		N/A	4.36%	N/A
KLA-Tencor	$16,131	2.80%	4.80%	4.80%	7.60%	4.80%
Kohl's Corp.	$11,334	3.93%	10.75%	10.75%	14.68%	10.75%
Kraft Heinz Co.	$58,585	5.23%	5.62%	5.62%	10.85%	5.62%
Kroger Co.	$22,607	2.21%	5.50%	5.50%	7.71%	5.50%
L Brands	$7,656	4.42%	1.07%	1.07%	5.49%	N/A
L3 Technologies	$15,474	1.61%	9.57%	9.57%	11.18%	9.57%
Laboratory Corp.	$14,130	0.00%	N/A	N/A	0.00%	N/A
Lam Research	$26,011	2.55%	16.44%	16.44%	18.99%	16.44%
Lamb Weston Holdings	$10,591	1.10%	9.70%	9.70%	10.80%	9.70%
Lauder (Estee)	$49,718	1.26%	9.76%	9.76%	11.02%	9.76%
Leggett & Platt	$5,342	3.71%	0.70%	0.70%	4.41%	N/A
Lennar Corp.	$15,662	0.34%	4.66%	4.66%	5.00%	N/A
Lilly (Eli)	$126,970	2.13%	13.61%	13.61%	15.75%	13.61%
Lincoln Nat'l Corp.	$12,562	2.59%	10.75%	10.75%	13.34%	10.75%
Linde plc	$46,923	1.99%		N/A	1.99%	N/A
LKQ Corp.	$8,343	0.00%	N/A	N/A	0.00%	N/A
Lockheed Martin	$82,395	3.17%	12.01%	12.01%	15.18%	12.01%
Loews Corp.	$15,086	0.52%	10.61%	10.61%	11.13%	10.61%

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions) [1]	Annual Dividend Yield [2]	Projected Growth Rate [3]	Projected Growth Rate Greater Than 0% and Less Than 20% [4]	Implied Cost of Equity Before Additional Screens [5] =[2]+[4]	Projected Growth Rate Accounting for Low-End Outlier Test [5]
Lowe's Cos.	$77,505	2.16%	15.27%	15.27%	17.43%	15.27%
LyondellBasell Inds.	$33,673	4.50%	6.66%	6.66%	11.16%	6.66%
M&T Bank Corp.	$23,275	2.44%		N/A	2.44%	N/A
Macerich Comp. (The)	$6,508	6.62%	6.65%	6.65%	13.27%	6.65%
Macy's Inc.	$8,086	5.87%	-2.69%	N/A	5.87%	N/A
Marathon Oil Corp.	$13,232	1.38%		N/A	1.38%	N/A
Marathon Petroleum	$29,883	3.24%	35.22%	N/A	3.24%	N/A
Marriott Int'l	$39,070	1.43%	18.57%	18.57%	20.00%	18.57%
Marsh & McLennan	$44,407	1.84%	8.73%	8.73%	10.56%	8.73%
Martin Marietta	$11,080	1.06%	12.15%	12.15%	13.21%	12.15%
Masco Corp.	$9,824	1.45%	15.76%	15.76%	17.22%	15.76%
MasterCard Inc.	$218,520	0.62%	20.79%	N/A	0.62%	N/A
Mattel Inc.	$4,069	0.00%	N/A	N/A	0.00%	N/A
Maxim Integrated	$15,036	3.37%	13.36%	13.36%	16.73%	13.36%
McCormick & Co.	$16,279	1.85%	9.23%	9.23%	11.08%	9.23%
McDonald's Corp.	$137,822	2.63%	6.55%	6.55%	9.18%	6.55%
Michael Kors Hldgs.		N/A	N/A	N/A	0.00%	N/A
Medtronic plc	$118,989	2.26%	8.24%	8.24%	10.51%	8.24%
Merck & Co.	$197,890	2.88%	9.42%	9.42%	12.29%	9.42%
MetLife Inc.	$45,060	3.82%	16.69%	16.69%	20.51%	16.69%
Mettler-Toledo Int'l	$15,983	0.00%	N/A	N/A	0.00%	N/A
MGM Resorts Int'l	$15,660	1.61%	-6.31%	N/A	1.61%	N/A
Microchip Technology	$18,984	1.83%	12.50%	12.50%	14.33%	12.50%
Micron Technology	$42,806	0.00%	N/A	N/A	0.00%	N/A
Microsoft Corp.	$802,022	1.79%	14.03%	14.03%	15.82%	14.03%
Mid-America Apartment	$11,510	3.81%		N/A	3.81%	N/A
Mohawk Inds.	$9,608	0.00%	N/A	N/A	0.00%	N/A
Molson Coors Brewing	$14,374	2.48%	5.61%	5.61%	8.09%	5.61%
Mondelez Int'l	$67,405	2.37%	6.78%	6.78%	9.15%	6.78%
Monster Beverage	$31,651	0.00%	N/A	N/A	0.00%	N/A
Moody's Corp.	$30,372	1.10%	13.60%	13.60%	14.70%	13.60%
Morgan Stanley	$73,001	2.87%	14.46%	14.46%	17.33%	14.46%
Mosaic Company	$12,443	0.61%	31.00%	N/A	0.61%	N/A
Motorola Solutions	$19,115	1.93%	14.62%	14.62%	16.55%	14.62%
MSCI Inc.	$15,085	1.46%	19.00%	19.00%	20.46%	19.00%
Mylan N.V.	$15,443	0.00%	N/A	N/A	0.00%	N/A
Nasdaq Inc.	$14,434	2.01%	9.24%	9.24%	11.25%	9.24%
National Oilwell Varco	$11,301	0.67%		N/A	0.67%	N/A
Nektar Therapeutics	$7,327	0.00%	N/A	N/A	0.00%	N/A
NetApp Inc.	$16,198	2.43%	17.20%	17.20%	19.63%	17.20%
Netflix Inc.	$148,051	0.00%	N/A	N/A	0.00%	N/A
Newell Brands	$10,395	4.32%	9.40%	9.40%	13.72%	9.40%
Newfield Exploration	$3,662	0.00%	N/A	N/A	0.00%	N/A
Newmont Mining	$18,169	1.65%	-1.24%	N/A	1.65%	N/A
News Corp. 'A'	$7,503	1.57%	12.57%	12.57%	14.14%	12.57%
News Corp. 'B'	$7,538	1.56%	12.57%	12.57%	14.13%	12.57%
NextEra Energy	$85,543	2.81%	7.45%	7.45%	10.26%	7.45%
Nielsen Hldgs. plc	$9,116	5.47%	4.56%	4.56%	10.03%	4.56%
NIKE Inc. 'B'	$129,125	1.08%	14.18%	14.18%	15.26%	14.18%
NiSource Inc.	$9,907	2.91%	6.05%	6.05%	8.97%	6.05%
Noble Energy	$10,719	1.97%	51.66%	N/A	1.97%	N/A
Nordstrom Inc.	$7,839	3.26%	8.87%	8.87%	12.14%	8.87%
Norfolk Southern	$45,684	2.03%	8.88%	8.88%	10.90%	8.88%
Northern Trust Corp.	$19,585	2.71%	14.22%	14.22%	16.93%	14.22%
Northrop Grumman	$47,871	1.76%	13.93%	13.93%	15.69%	13.93%
Norwegian Cruise Line	$11,398	0.00%	N/A	N/A	0.00%	N/A
NRG Energy	$11,861	0.29%	75.88%	N/A	0.29%	N/A
Nucor Corp.	$19,225	2.60%	10.69%	10.69%	13.29%	10.69%
NVIDIA Corp.	$87,688	0.44%	13.02%	13.02%	13.46%	13.02%

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions) [1]	Annual Dividend Yield [2]	Projected Growth Rate [3]	Projected Growth Rate Greater Than 0% and Less Than 20% [4]	Implied Cost of Equity Before Additional Screens [5] =[2]+[4]	Projected Growth Rate Accounting for Low-End Outlier Test [5]
Occidental Petroleum	$50,351	4.61%	54.43%	N/A	4.61%	N/A
Omnicom Group	$17,453	3.09%	6.80%	6.80%	9.89%	6.80%
ONEOK Inc.	$26,413	5.37%	37.29%	N/A	5.37%	N/A
Oracle Corp.	$182,435	1.50%	10.03%	10.03%	11.53%	10.03%
O'Reilly Automotive	$27,692	0.00%	N/A	N/A	0.00%	N/A
PACCAR Inc.	$22,919	5.05%	4.08%	4.08%	9.13%	4.08%
Packaging Corp.	$8,913	3.32%	10.61%	10.61%	13.93%	10.61%
Parker-Hannifin	$21,812	1.85%	9.37%	9.37%	11.22%	9.37%
Paychex Inc.	$25,424	3.45%	9.46%	9.46%	12.91%	9.46%
PayPal Holdings	$104,559	0.00%	N/A	N/A	0.00%	N/A
Pentair plc	$7,151	1.76%		N/A	1.76%	N/A
People's United Fin'l	$5,608	4.28%	13.73%	13.73%	18.01%	13.73%
PepsiCo Inc.	$159,090	3.31%	6.86%	6.86%	10.17%	6.86%
PerkinElmer Inc.	$10,053	0.31%	14.42%	14.42%	14.73%	14.42%
Perrigo Co. plc	$6,311	1.81%	8.87%	8.87%	10.68%	8.87%
Pfizer Inc.	$245,381	3.36%	8.63%	8.63%	11.99%	8.63%
PG&E Corp.	$6,722	0.00%	N/A	N/A	0.00%	N/A
Philip Morris Int'l	$119,263	6.02%	5.99%	5.99%	12.01%	5.99%
Phillips 66	$43,996	3.62%	41.00%	N/A	3.62%	N/A
Praxair Inc.		N/A	N/A	N/A	0.00%	N/A
Pioneer Natural Res.	$24,260	0.35%	70.53%	N/A	0.35%	N/A
PNC Financial Serv.	$56,674	3.10%	8.33%	8.33%	11.43%	8.33%
PPG Inds.	$25,294	1.82%	8.68%	8.68%	10.49%	8.68%
PPL Corp.	$22,541	5.39%	3.59%	3.59%	8.98%	3.59%
Price (T. Rowe) Group	$22,673	3.10%	3.97%	3.97%	7.07%	3.97%
Principal Fin'l Group	$14,200	4.35%	6.38%	6.38%	10.73%	6.38%
Procter & Gamble	$241,327	2.95%	6.97%	6.97%	9.92%	6.97%
Progressive Corp.	$39,237	1.75%	14.89%	14.89%	16.64%	14.89%
Prologis	$36,806	2.88%		N/A	2.88%	N/A
Prudential Fin'l	$38,182	3.87%	8.73%	8.73%	12.60%	8.73%
Public Serv. Enterprise	$27,493	3.45%	7.21%	7.21%	10.65%	7.21%
Public Storage	$36,947	4.15%	8.00%	8.00%	12.15%	8.00%
PulteGroup Inc.	$7,844	1.61%	0.47%	0.47%	2.07%	N/A
PVH Corp.	$8,283	0.14%	13.50%	13.50%	13.64%	13.50%
Qorvo Inc.	$8,173	0.00%	N/A	N/A	0.00%	N/A
Qualcomm Inc.	$60,365	5.30%	14.36%	14.36%	19.66%	14.36%
Quanta Services	$5,256	0.46%	22.37%	N/A	0.46%	N/A
Quest Diagnostics	$11,880	2.42%	6.97%	6.97%	9.39%	6.97%
Ralph Lauren	$9,349	2.16%	11.31%	11.31%	13.47%	11.31%
Raymond James Fin'l	$11,724	1.72%	8.39%	8.39%	10.12%	8.39%
Raytheon Co.	$46,957	2.09%	18.59%	18.59%	20.68%	18.59%
Realty Income Corp.	$19,523	4.00%	5.00%	5.00%	9.00%	5.00%
Red Hat Inc.	$31,435	0.00%	N/A	N/A	0.00%	N/A
Regency Centers Corp.	$11,102	3.44%		N/A	3.44%	N/A
Regeneron Pharmac.	$45,631	0.00%	N/A	N/A	0.00%	N/A
Regions Financial	$16,633	3.78%		N/A	3.78%	N/A
Republic Services	$24,900	1.99%	15.75%	15.75%	17.74%	15.75%
ResMed Inc.	$13,561	1.58%	13.97%	13.97%	15.55%	13.97%
Robert Half Int'l	$7,820	1.89%	7.10%	7.10%	8.99%	7.10%
Rockwell Automation	$20,529	2.33%	10.28%	10.28%	12.61%	10.28%
Rollins Inc.	$12,189	1.12%	8.20%	8.20%	9.32%	8.20%
Roper Tech.	$29,298	0.63%	9.30%	9.30%	9.93%	9.30%
Ross Stores	$34,182	1.05%	12.61%	12.61%	13.65%	12.61%
Royal Caribbean	$25,088	2.37%	12.40%	12.40%	14.77%	12.40%
S&P Global	$48,085	1.11%	13.70%	13.70%	14.81%	13.70%
salesforce.com	$116,257	0.00%	N/A	N/A	0.00%	N/A
SBA Communications	$21,255	0.00%	N/A	N/A	0.00%	N/A
Schein (Henry)	$11,844	0.00%	N/A	N/A	0.00%	N/A
Schlumberger Ltd.	$61,222	4.49%	21.30%	N/A	4.49%	N/A

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions) [1]	Annual Dividend Yield [2]	Projected Growth Rate [3]	Projected Growth Rate Greater Than 0% and Less Than 20% [4]	Implied Cost of Equity Before Additional Screens [5] =[2]+[4]	Projected Growth Rate Accounting for Low-End Outlier Test [5]
Schwab (Charles)	$63,221	1.11%	23.92%	N/A	1.11%	N/A
Seagate Technology	$12,670	5.57%	6.19%	6.19%	11.75%	6.19%
Sealed Air	$6,199	1.60%	18.68%	18.68%	20.28%	18.68%
Sempra Energy	$32,053	3.32%	8.69%	8.69%	12.01%	8.69%
Sherwin-Williams	$39,465	0.83%	16.14%	16.14%	16.98%	16.14%
Simon Property Group	$56,668	4.74%		N/A	4.74%	N/A
Skyworks Solutions	$12,957	2.06%	N/A	N/A	2.06%	N/A
SL Green Realty	$8,675	3.78%		N/A	3.78%	N/A
Smith (A.O.)	$8,134	1.83%	9.35%	9.35%	11.18%	9.35%
Smucker (J.M.)	$11,935	3.33%	8.40%	8.40%	11.73%	8.40%
Snap-on Inc.	$9,325	2.30%	9.85%	9.85%	12.15%	9.85%
Southern Co.	$48,551	5.07%	1.68%	1.68%	6.75%	1.68%
Stericycle Inc.		N/A	N/A	N/A	0.00%	N/A
Stanley Black & Decker	$19,100	2.11%	8.31%	8.31%	10.42%	8.31%
Starbucks Corp.	$84,719	2.23%	13.17%	13.17%	15.40%	13.17%
State Street Corp.	$26,906	2.64%	7.99%	7.99%	10.63%	7.99%
Stryker Corp.	$66,444	1.17%	10.54%	10.54%	11.71%	10.54%
SunTrust Banks	$26,697	3.62%	9.82%	9.82%	13.43%	9.82%
SVB Fin'l Group	$12,428	0.00%	N/A	N/A	0.00%	N/A
Symantec Corp.	$13,285	1.31%	12.23%	12.23%	13.54%	12.23%
Synchrony Financial	$21,590	2.83%	20.05%	N/A	2.83%	N/A
Synopsys Inc.	$13,056	0.00%	N/A	N/A	0.00%	N/A
Sysco Corp.	$33,212	2.45%	11.28%	11.28%	13.73%	11.28%
Take-Two Interactive	$12,012	0.00%	N/A	N/A	0.00%	N/A
Tapestry Inc.	$11,218	3.49%	9.58%	9.58%	13.07%	9.58%
Target Corp.	$38,092	3.60%	8.00%	8.00%	11.60%	8.00%
TE Connectivity	$28,471	2.16%	10.40%	10.40%	12.56%	10.40%
TechnipFMC	$10,399	2.24%	22.93%	N/A	2.24%	N/A
Texas Instruments	$97,142	3.02%	8.04%	8.04%	11.06%	8.04%
Textron Inc.	$12,929	0.15%	17.30%	17.30%	17.45%	17.30%
Thermo Fisher Sci.	$98,901	0.28%	10.80%	10.80%	11.07%	10.80%
Tiffany & Co.	$10,816	2.66%	10.34%	10.34%	13.00%	10.34%
TJX Companies	$61,324	1.64%	11.64%	11.64%	13.28%	11.64%
Torchmark Corp.	$9,395	0.76%	10.50%	10.50%	11.26%	10.50%
Total System Svcs.	$16,349	0.57%	14.22%	14.22%	14.79%	14.22%
Tractor Supply	$10,429	1.56%	12.32%	12.32%	13.88%	12.32%
TransDigm Group	$20,619	0.00%	N/A	N/A	0.00%	N/A
Travelers Cos.	$33,243	2.43%	17.12%	17.12%	19.56%	17.12%
TripAdvisor Inc.	$7,896	0.00%	N/A	N/A	0.00%	N/A
Twenty-First Century Fox	$91,349	0.73%	8.48%	8.48%	9.21%	8.48%
Twenty-First Century Fox 'B'	$90,886	0.73%	9.20%	9.20%	9.93%	9.20%
Twitter Inc.	$25,519	0.00%	N/A	N/A	0.00%	N/A
Tyson Foods 'A'	$22,663	2.42%	3.20%	3.20%	5.62%	N/A
U.S. Bancorp	$83,035	3.00%	6.81%	6.81%	9.81%	6.81%
UDR Inc.	$11,717	2.97%		N/A	2.97%	N/A
Ulta Beauty	$17,358	0.00%	N/A	N/A	0.00%	N/A
Under Armour 'A'	$9,298	0.00%	N/A	N/A	0.00%	N/A
Under Armour 'C'	$8,426	0.00%	N/A	N/A	0.00%	N/A
Union Pacific	$117,317	2.00%	16.43%	16.43%	18.43%	16.43%
United Cont'l Hldgs.	$23,778	0.00%	N/A	N/A	0.00%	N/A
United Parcel Serv.	$90,539	3.66%	10.56%	10.56%	14.22%	10.56%
United Rentals	$10,213	0.00%	N/A	N/A	0.00%	N/A
United Technologies	$94,572	2.47%	8.45%	8.45%	10.92%	8.45%
UnitedHealth Group	$259,932	1.34%	15.80%	15.80%	17.14%	15.80%
Universal Health `B'	$12,261	0.30%	13.55%	13.55%	13.84%	13.55%
Unum Group	$7,603	2.99%	10.08%	10.08%	13.07%	10.08%
V.F. Corp.	$33,429	2.42%	13.39%	13.39%	15.81%	13.39%
Valero Energy	$37,292	4.22%	34.06%	N/A	4.22%	N/A
Varian Medical Sys.	$12,081	0.00%	N/A	N/A	0.00%	N/A

Table No. BV-9

Electric Utility Sample

CAPM Projected Growth Rate based on S&P 500 Dividend-Paying Stocks

Company Name	Market Cap ($Millions)	Annual Dividend Yield	Projected Growth Rate	Projected Growth Rate Greater Than 0% and Less Than 20%	Implied Cost of Equity Before Additional Screens	Projected Growth Rate Accounting for Low-End Outlier Test
	[1]	[2]	[3]	[4]	[5] =[2]+[4]	[5]
Ventas Inc.	$22,906	5.11%	9.70%	9.70%	14.81%	9.70%
VeriSign Inc.	$20,508	0.00%	N/A	N/A	0.00%	N/A
Verisk Analytics	$19,351	0.00%	N/A	N/A	0.00%	N/A
Verizon Communic.	$227,509	4.42%	9.45%	9.45%	13.87%	9.45%
Vertex Pharmac.	$48,799	0.00%	N/A	N/A	0.00%	N/A
Viacom Inc. 'B'	$11,859	2.71%	5.30%	5.30%	8.01%	5.30%
Visa Inc.	$274,745	0.77%	15.79%	15.79%	16.56%	15.79%
Vornado R'lty Trust	$13,303	3.80%	2.80%	2.80%	6.60%	2.80%
Vulcan Materials	$13,422	1.07%	25.85%	N/A	1.07%	N/A
Walgreens Boots	$68,173	2.45%	10.12%	10.12%	12.57%	10.12%
Walmart Inc.	$278,411	2.26%	5.01%	5.01%	7.27%	5.01%
Waste Management	$40,863	1.95%	14.30%	14.30%	16.25%	14.30%
Waters Corp.	$17,510	0.00%	N/A	N/A	0.00%	N/A
WEC Energy Group	$23,043	3.24%	4.70%	4.70%	7.94%	4.70%
WellCare Health Plans	$13,819	0.00%	N/A	N/A	0.00%	N/A
Wells Fargo	$230,443	3.74%	10.94%	10.94%	14.68%	10.94%
Welltower Inc.	$28,805	4.67%	13.00%	13.00%	17.67%	13.00%
Western Digital	$13,002	4.26%	-9.50%	N/A	4.26%	N/A
Western Union	$8,098	4.11%	3.83%	3.83%	7.94%	3.83%
WestRock Co.	$10,320	4.70%	14.97%	14.97%	19.67%	14.97%
Weyerhaeuser Co.	$19,659	5.08%	6.50%	6.50%	11.58%	6.50%
Whirlpool Corp.	$8,513	3.46%	8.87%	8.87%	12.33%	8.87%
Williams Cos.	$32,600	4.96%	8.00%	8.00%	12.96%	8.00%
Willis Towers Watson plc	$21,139	1.44%	13.32%	13.32%	14.76%	13.32%
Wynn Resorts	$13,375	2.38%		N/A	2.38%	N/A
Xcel Energy Inc.	$26,876	3.07%	6.60%	6.60%	9.66%	6.60%
Xerox Corp.	$6,916	3.51%		N/A	3.51%	N/A
Xilinx Inc.	$28,339	1.29%	19.90%	19.90%	21.19%	19.90%
Xylem Inc.	$12,805	1.37%	18.91%	18.91%	20.27%	18.91%
Yum! Brands	$29,416	1.78%	11.90%	11.90%	13.68%	11.90%
Zimmer Biomet Hldgs.	$22,350	0.86%	3.88%	3.88%	4.74%	N/A
Zions Bancorp.	$9,145	2.48%	10.90%	10.90%	13.38%	10.90%
Zoetis Inc.	$41,441	0.76%	16.22%	16.22%	16.98%	16.22%
Weighted Average		**2.58%**	**12.21%**	**10.68%**	**9.24%**	**10.78%**

Notes & Sources:

[1]-[2]: Value Line Analyzer as of January 31, 2019. Annual dividend yield calculated by dividing annual dividend yield by current stock price.

[3]: Thomson Reuters as of January 31, 2019.

[4]: Excludes growth rates less than or equal to 0% and growth rates greater than or equal to 20%.

[5]: Adheres to the low-end outlier test, which excludes companies that have a lower implied return on equity than cost of debt for BBB bonds plus one hundred basis points.

Table No. BV-10

Electric Utility Sample

Expected Earnings Method Applied to the FERC Electric Sample

Company	2021-23 Expected Return on Equity [1]	Adjustment Factor [2]	Adjusted Return on Equity [3]=[1]*[2]
FirstEnergy Corp.	16.50%	1.039	17.15%
CMS Energy Corp.	14.00%	1.032	14.45%
PPL Corp.	13.50%	102.90%	13.89%
NextEra Energy	13.00%	1.023	13.29%
Edison Int'l	12.50%	1.020	12.75%
Southern Co.	12.50%	1.019	12.74%
Sempra Energy	12.00%	1.028	12.34%
WEC Energy Group	12.00%	1.013	12.16%
OGE Energy	11.50%	1.013	11.64%
Otter Tail Corp.	11.00%	1.042	11.47%
DTE Energy	11.00%	1.030	11.33%
Entergy Corp.	11.00%	1.029	11.32%
Amer. Elec. Power	11.00%	1.022	11.25%
Public Serv. Enterprise	11.00%	1.018	11.20%
Xcel Energy Inc.	10.50%	1.021	10.72%
Ameren Corp.	10.50%	1.021	10.72%
Pinnacle West Capital	10.50%	1.017	10.67%
Alliant Energy	10.50%	1.005	10.55%
PNM Resources	9.50%	1.025	9.74%
Exelon Corp.	9.50%	1.022	9.71%
Hawaiian Elec.	9.50%	1.021	9.70%
IDACORP Inc.	9.50%	1.017	9.66%
Eversource Energy	9.50%	1.014	9.64%
Evergy Inc.	9.50%	0.991	9.41%
MGE Energy	9.00%	1.045	9.40%
ALLETE	9.00%	1.015	9.14%
Portland General	9.00%	1.014	9.12%
NorthWestern Corp.	9.00%	1.012	9.11%
El Paso Electric	8.50%	1.013	8.61%
Consol. Edison	8.50%	1.013	8.61%
Duke Energy	8.50%	1.011	8.59%
AVANGRID Inc.	6.50%	1.007	6.55%
Unitil Corp.	N/A	N/A	N/A
Minimum			**6.55%**
Maximum			17.15%
Midpoint			11.85%
Median			10.70%
Median outlier Tested			10.67%
Upper end of ZOR			**14.45%**
Upper Midpoint			12.5%

Sources and Notes:
[1]: Value Line Investment Analyzer as of 01/31/2019.
FirstEnergy Corp. is encluded from the ROE estimation because it fails the outlier test.
Unitil Corp. is excluded from the sample due to data inavailability.

Workpaper to BV-4

Monthly High, Low, Average Price for Electric Sample

	Monthly High Intraday Price						Monthly Low Intraday Price						Monthly Average Price					
Company	Month Ending Aug 31, 2018	Month Ending Sep 30, 2018	Month Ending Oct 31, 2018	Month Ending Nov 30, 2018	Month Ending Dec 31, 2018	Month Ending Jan 31, 2019	Month Ending Aug 31, 2018	Month Ending Sep 30, 2018	Month Ending Oct 31, 2018	Month Ending Nov 30, 2018	Month Ending Dec 31, 2018	Month Ending Jan 31, 2019	Month Ending Aug 31, 2018	Month Ending Sep 30, 2018	Month Ending Oct 31, 2018	Month Ending Nov 30, 2018	Month Ending Dec 31, 2018	Month Ending Jan 31, 2019
ALLETE	$79.42	$77.33	$78.60	$81.59	$82.82	$77.04	$74.47	$73.39	$73.49	$72.75	$72.42	$72.50	$76.95	$75.36	$76.05	$77.17	$77.62	$74.77
Alliant Energy	$43.84	$44.18	$44.70	$46.05	$46.58	$44.55	$41.39	$41.73	$42.01	$42.22	$40.68	$40.75	$42.62	$42.96	$43.36	$44.14	$43.63	$42.65
Amer. Elec. Power	$72.91	$73.74	$76.05	$78.47	$81.05	$79.61	$69.32	$68.92	$69.31	$72.07	$72.53	$72.26	$71.11	$71.33	$72.68	$75.27	$76.79	$75.93
Ameren Corp.	$65.09	$66.11	$67.23	$70.68	$70.95	$69.62	$60.78	$62.06	$62.70	$63.32	$62.51	$63.13	$62.94	$64.08	$64.97	$67.00	$66.73	$66.38
CMS Energy Corp.	$50.12	$50.81	$51.91	$52.25	$53.82	$52.36	$47.18	$47.70	$48.13	$47.92	$47.63	$47.97	$48.65	$49.26	$50.02	$50.09	$50.73	$50.17
DTE Energy	$114.12	$114.31	$118.22	$121.00	$120.76	$118.32	$106.27	$106.41	$107.39	$110.41	$107.22	$107.33	$110.19	$110.36	$112.81	$115.71	$113.99	$112.83
Entergy Corp.	$85.62	$85.81	$86.00	$87.85	$90.79	$89.49	$80.70	$78.99	$79.57	$82.08	$82.06	$83.24	$83.16	$82.40	$82.78	$84.96	$86.43	$86.36
Evergy Inc.	$58.24	$59.28	$57.69	$61.10	$61.00	$57.86	$54.94	$54.19	$54.26	$55.49	$55.18	$55.13	$56.59	$56.74	$55.98	$58.30	$58.09	$56.49
MGE Energy	$67.40	$68.05	$66.39	$66.26	$68.95	$66.16	$63.03	$62.45	$60.57	$60.29	$56.64	$56.74	$65.21	$65.25	$63.48	$63.27	$62.80	$61.45
OGE Energy	$37.69	$37.75	$38.13	$39.97	$41.80	$41.19	$35.58	$35.29	$35.91	$35.55	$37.67	$38.04	$36.63	$36.52	$37.02	$37.76	$39.74	$39.62
Otter Tail Corp.	$49.75	$49.35	$48.74	$49.14	$51.88	$49.33	$47.35	$46.85	$44.82	$44.22	$46.26	$45.94	$48.55	$48.10	$46.78	$46.68	$49.07	$47.64
WEC Energy Group	$68.48	$69.52	$72.09	$72.63	$75.48	$73.51	$64.92	$64.96	$66.16	$66.46	$66.75	$67.21	$66.70	$67.24	$69.12	$69.55	$71.11	$70.36
AVANGRID Inc.	$51.21	$50.67	$49.55	$51.11	$53.47	$50.22	$49.00	$46.96	$45.81	$46.92	$48.05	$47.45	$50.11	$48.82	$47.68	$49.02	$50.76	$48.84
Consol. Edison	$81.53	$81.55	$79.18	$80.39	$84.32	$77.99	$77.09	$74.31	$74.64	$73.93	$73.85	$73.30	$79.31	$77.93	$76.91	$77.16	$79.09	$75.64
Duke Energy	$82.72	$83.77	$85.08	$89.23	$91.35	$88.48	$79.51	$78.00	$78.52	$80.89	$82.77	$82.46	$81.11	$80.89	$81.80	$85.06	$87.06	$85.47
Eversource Energy	$63.53	$63.88	$65.29	$68.39	$70.53	$69.82	$59.30	$60.15	$60.56	$61.57	$62.61	$63.10	$61.42	$62.02	$62.93	$64.98	$66.57	$66.46
Exelon Corp.	$45.05	$44.85	$44.87	$46.45	$47.40	$47.93	$41.72	$42.19	$42.44	$43.02	$43.10	$43.51	$43.39	$43.52	$43.65	$44.74	$45.25	$45.72
FirstEnergy Corp.	$37.74	$38.37	$39.01	$39.38	$39.88	$39.43	$35.37	$35.88	$36.32	$36.53	$35.33	$36.29	$36.56	$37.12	$37.67	$37.96	$37.61	$37.86
NextEra Energy	$175.65	$174.81	$176.83	$183.65	$184.20	$180.88	$165.45	$164.25	$166.19	$166.75	$164.78	$168.66	$170.55	$169.53	$171.51	$175.20	$174.49	$174.77
PPL Corp.	$30.21	$31.10	$31.38	$32.46	$31.42	$31.38	$28.16	$28.33	$29.11	$30.23	$27.31	$27.80	$29.19	$29.72	$30.24	$31.35	$29.37	$29.59
Public Serv. Enterprise	$54.35	$53.84	$56.68	$55.94	$56.33	$54.68	$50.01	$50.65	$51.59	$52.33	$49.23	$49.97	$52.18	$52.25	$54.14	$54.14	$52.78	$52.33
Southern Co.	$49.43	$45.98	$46.33	$47.69	$47.98	$48.68	$43.63	$42.57	$42.51	$44.33	$42.50	$43.26	$46.53	$44.28	$44.42	$46.01	$45.24	$45.97
Unitil Corp.	$51.98	$52.79	$51.26	$51.47	$52.74	$53.11	$48.57	$49.02	$47.13	$46.21	$48.49	$47.05	$50.27	$50.91	$49.19	$48.84	$50.62	$50.08
Edison Int'l	$70.62	$69.90	$71.00	$70.13	$60.15	$59.43	$64.90	$65.76	$66.96	$45.50	$53.43	$53.40	$67.76	$67.83	$68.98	$57.82	$56.79	$56.42
El Paso Electric	$64.35	$63.05	$60.22	$59.27	$57.33	$52.62	$60.95	$56.88	$55.95	$54.45	$48.38	$47.99	$62.65	$59.96	$58.09	$56.86	$52.86	$50.31
Hawaiian Elec.	$36.03	$36.33	$37.69	$38.38	$39.35	$37.23	$34.16	$34.78	$34.88	$36.58	$35.15	$35.06	$35.10	$35.55	$36.29	$37.48	$37.25	$36.15
IDACORP Inc.	$99.28	$101.49	$101.89	$101.41	$102.44	$97.69	$92.03	$96.81	$92.94	$93.06	$89.91	$89.31	$95.66	$99.15	$97.42	$97.24	$96.18	$93.50
NorthWestern Corp.	$62.16	$60.97	$62.19	$64.76	$65.74	$64.11	$58.03	$56.93	$56.23	$58.33	$57.28	$57.33	$60.10	$58.95	$59.21	$61.55	$61.51	$60.72
Pinnacle West Capital	$82.83	$81.12	$86.71	$90.06	$92.64	$88.42	$78.27	$77.19	$78.11	$81.51	$83.14	$81.63	$80.55	$79.16	$82.41	$85.79	$87.89	$85.03
PNM Resources	$40.95	$40.75	$40.59	$43.29	$45.35	$43.20	$38.25	$38.15	$37.90	$37.67	$39.52	$39.71	$39.60	$39.45	$39.25	$40.48	$42.43	$41.46
Portland General	$47.56	$47.54	$47.53	$49.21	$50.40	$48.49	$44.38	$44.44	$43.94	$44.40	$43.73	$44.03	$45.97	$45.99	$45.74	$46.81	$47.07	$46.26
Sempra Energy	$118.06	$127.22	$117.89	$118.80	$119.11	$117.16	$113.39	$110.99	$109.81	$108.64	$104.88	$106.09	$115.73	$119.11	$113.85	$113.72	$112.00	$111.63
Xcel Energy Inc.	$48.72	$49.49	$50.53	$52.49	$54.11	$52.58	$45.87	$46.01	$46.52	$47.44	$48.16	$47.70	$47.30	$47.75	$48.52	$49.97	$51.13	$50.14

Sources and Note: Bloomberg as of 1/31/2019. Monthly average calculated as (Monthly High Price + Monthly Low Price)/2

Workpaper to BV-10

Electric Utility

Adjustment Factor Calculation for FERC Electric Utility Sample

Company	2018			2023				
	Equity Ratio	Total Capital (Millions)	Total Common Equity (Millions)	Equity Ratio	Total Capital (Millions)	Total Common Equity (Millions)	Change in Equity	Adjustment Factor
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
ALLETE	59.0%	$3,640	$2,148	59.5%	$4,200	$2,499	3.1%	1.0152
Alliant Energy	48.0%	$8,300	$3,984	48.0%	$8,700	$4,176	0.9%	1.0047
Amer. Elec. Power	45.5%	$41,975	$19,099	48.0%	$49,800	$23,904	4.6%	1.0224
Ameren Corp.	49.0%	$15,650	$7,669	49.5%	$19,100	$9,455	4.3%	1.0209
CMS Energy Corp.	35.5%	$13,625	$4,837	38.0%	$17,500	$6,650	6.6%	1.0318
DTE Energy	42.5%	$24,100	$10,243	44.0%	$31,300	$13,772	6.1%	1.0296
Entergy Corp.	35.0%	$24,275	$8,496	38.5%	$29,400	$11,319	5.9%	1.0287
Evergy Inc.	57.0%	$15,675	$8,935	52.5%	$15,500	$8,138	-1.9%	0.9907
MGE Energy	62.5%	$1,325	$828	66.5%	$1,950	$1,297	9.4%	1.0448
OGE Energy	56.0%	$7,140	$3,998	53.0%	$8,550	$4,532	2.5%	1.0125
Otter Tail Corp.	55.0%	$1,360	$748	60.5%	$1,890	$1,143	8.9%	1.0424
WEC Energy Group	51.0%	$19,225	$9,805	51.5%	$21,700	$11,176	2.7%	1.0131
AVANGRID Inc.	71.5%	$21,350	$15,265	63.5%	$25,900	$16,447	1.5%	1.0075
Consol. Edison	51.0%	$32,075	$16,358	51.5%	$36,100	$18,592	2.6%	1.0128
Duke Energy	45.5%	$96,625	$43,964	43.5%	$112,400	$48,894	2.1%	1.0106
Eversource Energy	47.5%	$24,375	$11,578	44.5%	$30,000	$13,350	2.9%	1.0142
Exelon Corp.	47.5%	$65,775	$31,243	50.0%	$78,000	$39,000	4.5%	1.0222
FirstEnergy Corp.	25.0%	$24,675	$6,169	31.0%	$29,500	$9,145	8.2%	1.0394
NextEra Energy	53.5%	$64,000	$34,240	54.0%	$79,500	$42,930	4.6%	1.0226
PPL Corp.	37.5%	$32,300	$12,113	44.0%	$36,800	$16,192	6.0%	1.0290
Public Serv. Enterprise	53.0%	$27,350	$14,496	50.5%	$34,500	$17,423	3.7%	1.0184
Southern Co.	36.5%	$69,100	$25,222	39.5%	$77,300	$30,534	3.9%	1.0191
Unitil Corp.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Edison Int'l	44.0%	$27,400	$12,056	46.0%	$32,100	$14,766	4.1%	1.0203
El Paso Electric	46.0%	$2,565	$1,180	44.5%	$3,025	$1,346	2.7%	1.0132
Hawaiian Elec.	54.5%	$3,985	$2,172	55.0%	$4,850	$2,668	4.2%	1.0206
IDACORP Inc.	56.0%	$4,195	$2,349	57.0%	$4,875	$2,779	3.4%	1.0168
NorthWestern Corp.	50.5%	$3,790	$1,914	53.5%	$4,025	$2,153	2.4%	1.0118
Pinnacle West Capital	52.0%	$9,975	$5,187	54.5%	$11,225	$6,118	3.4%	1.0165
PNM Resources	40.0%	$4,280	$1,712	42.0%	$5,250	$2,205	5.2%	1.0253
Portland General	53.0%	$4,730	$2,507	52.0%	$5,525	$2,873	2.8%	1.0136
Sempra Energy	41.0%	$37,875	$15,529	44.5%	$46,300	$20,604	5.8%	1.0283
Xcel Energy Inc.	43.0%	$28,775	$12,373	43.0%	$35,600	$15,308	4.3%	1.0213

Sources and Notes:
[1]-[2]&[4]-[5]: Value Line Investment Analyzer as of 01/31/2019.
[3]=[1]*[2]
[6]=[4]*[5]
[7]=([6]/[3])^(1/5)-1
[8]=(2+2*[7])/(2+[7])
*Data not available for Unitil Corporation.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER19-______-000**
	)	

<u>EXHIBIT SCE-28</u>

EXHIBIT TO THE TESTIMONY OF
DR. BENTE VILLADSEN

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

APRIL 2019

BV-C1: Table of Content

The table numbering follow that of the FERC Electric Sample.

Table No. BV-C3

CINI Sample

Summary of Cost of Equity Estimates using IBES Growth Forecast

DCF Cost of Equity

Company	S&P Credit Rating	Dividend Yield	Adjusted Dividend Yield	GDP Growth Forecast	IBES Growth Estimate	Combined Growth Rate	Implied Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Delta Air Lines	BBB-	2.53%	2.69%	4.24%	16.82%	12.63%	15.3%
Southwest Airlines	BBB+	1.16%	1.23%	4.24%	15.90%	12.01%	13.2%
FedEx Corp.	BBB	1.14%	1.19%	4.24%	9.71%	7.88%	9.1%
United Parcel Serv.	A+	3.22%	3.37%	4.24%	11.59%	9.14%	12.5%
Atmos Energy	A	2.13%	2.19%	4.24%	6.45%	5.71%	7.9%
Chesapeake Utilities	A-	1.75%	-	4.24%	n/a	-	-
NiSource Inc.	BBB+	3.00%	3.08%	4.24%	5.92%	5.36%	8.4%
Northwest Natural	A	2.89%	2.95%	4.24%	4.00%	4.08%	7.0%
ONE Gas Inc.	A	2.30%	2.36%	4.24%	5.50%	5.08%	7.4%
Southwest Gas	BBB+	2.63%	2.70%	4.24%	6.20%	5.55%	8.2%
Spire Inc.	A-	3.06%	3.10%	4.24%	2.70%	3.21%	6.3%
Enable Midstream Part.	BBB-	8.05%	8.30%	2.12%	8.10%	6.11%	14.4%
Enterprise Products	BBB+	6.24%	6.46%	2.12%	9.39%	6.97%	13.4%
Magellan Midstream	BBB+	5.90%	6.08%	2.12%	8.02%	6.05%	12.1%
CSX Corp.	BBB+	1.25%	1.36%	4.24%	23.21%	16.89%	18.2%
GATX Corp.	BBB	2.17%	2.27%	4.24%	12.00%	9.41%	11.7%
Kansas City South'n	BBB	1.34%	1.41%	4.24%	14.70%	11.21%	12.6%
Union Pacific	A-	2.12%	2.26%	4.24%	18.27%	13.59%	15.9%
Heartland Express	n/a	0.41%	0.45%	4.24%	27.11%	19.49%	19.9%
Ryder System	BBB+	3.32%	3.50%	4.24%	14.61%	11.15%	14.7%
Amer. States Water	A+	1.76%	1.81%	4.24%	6.00%	5.41%	7.2%
Amer. Water Works	A	2.04%	2.11%	4.24%	8.20%	6.88%	9.0%
Middlesex Water	A	1.93%	-	4.24%	n/a	-	-
York Water Co. (The)	A-	2.13%	-	4.24%	n/a	-	-
MDU Resources	BBB+	2.99%	-	4.24%	n/a	-	-
EOG Resources	A-	0.72%	0.97%	4.24%	102.56%	69.79%	70.8%
National Fuel Gas	BBB	3.12%	-	4.24%	n/a	-	-
						Minimum	6.3%
						Maximum	70.8%
						Median	12.3%
						Maximum (Outlier Tested)	18.2%

Sources and Notes:
[1]: Bloomberg as of December 31, 2018.
[2]: See Table BV-C4.
[3] = [2] x (1 + (0.5 x [6])
[4]: See Table No. BV-7. GDP forecast halved for MLPs.
[5]: See Table BV-C5.
[6] = {(1/3) × [4]} + {(2/3) × [5]}
[7] = [3] + [6]
* Companies are excluded for (i) the low spread between cost of equity and cost of debt, and/or (ii) negative growth rate.

Table BV-C4

CINI Sample

Calculation of Dividend Yields

Company	Average Monthly Stock Price as of Jul 31, 2018 [1]	Average Monthly Stock Price as of Aug 31, 2018 [2]	Average Monthly Stock Price as of Sep 30, 2018 [3]	Average Monthly Stock Price as of Oct 31, 2018 [4]	Average Monthly Stock Price as of Nov 30, 2018 [5]	Average Monthly Stock Price as of Dec 31, 2018 [6]	Annualized Monthly Dividend as of Jul. 31, 2018 [7]	Annualized Monthly Dividend as of Aug. 31, 2018 [8]	Annualized Monthly Dividend as of Sep. 30, 2018 [9]	Annualized Monthly Dividend as of Oct. 31, 2018 [10]	Annualized Monthly Dividend as of Nov. 30, 2018 [11]	Annualized Monthly Dividend as of Dec. 31, 2018 [12]	Dividend Yield as of Jul. 31, 2018 [13]	Dividend Yield as of Aug. 31, 2018 [14]	Dividend Yield as of Sep. 30, 2018 [15]	Dividend Yield as of Oct. 31, 2018 [16]	Dividend Yield as of Nov. 30, 2018 [17]	Dividend Yield as of Dec. 31, 2018 [18]	Average Dividend Yield [19]
Delta Air Lines	$51.79	$55.90	$57.96	$53.91	$58.04	$54.49	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	2.70%	2.50%	2.42%	2.60%	2.41%	2.57%	2.53%
Southwest Airlines	$54.92	$58.91	$62.34	$55.15	$51.98	$49.98	$0.64	$0.64	$0.64	$0.64	$0.64	$0.64	1.17%	1.09%	1.03%	1.16%	1.23%	1.28%	1.16%
FedEx Corp.	$236.94	$245.54	$248.38	$225.73	$225.10	$192.72	$2.60	$2.60	$2.60	$2.60	$2.60	$2.60	1.10%	1.06%	1.05%	1.15%	1.16%	1.35%	1.14%
United Parcel Serv.	$113.15	$121.08	$120.41	$111.52	$110.46	$103.59	$3.64	$3.64	$3.64	$3.64	$3.64	$3.64	3.22%	3.01%	3.02%	3.26%	3.30%	3.51%	3.22%
Atmos Energy	$91.10	$92.33	$93.58	$94.98	$96.02	$93.84	$1.94	$1.94	$1.94	$1.94	$2.10	$2.10	2.13%	2.10%	2.07%	2.04%	2.19%	2.24%	2.13%
Chesapeake Utilities	$83.18	$83.33	$86.60	$86.09	$82.04	$85.30	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	1.78%	1.78%	1.71%	1.72%	1.80%	1.74%	1.75%
NiSource Inc.	$26.16	$26.60	$26.34	$25.25	$25.73	$26.05	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	2.98%	2.93%	2.96%	3.09%	3.03%	2.99%	3.00%
Northwest Natural	$64.63	$63.55	$67.54	$68.19	$67.13	$63.19	$1.89	$1.89	$1.89	$1.90	$1.90	$1.90	2.92%	2.97%	2.80%	2.79%	2.83%	3.01%	2.89%
ONE Gas Inc.	$75.73	$77.90	$80.85	$82.01	$81.72	$81.63	$1.84	$1.84	$1.84	$1.84	$1.84	$1.84	2.43%	2.36%	2.28%	2.24%	2.25%	2.25%	2.30%
Southwest Gas	$77.73	$78.41	$79.94	$80.01	$81.04	$78.16	$2.08	$2.08	$2.08	$2.08	$2.08	$2.08	2.68%	2.65%	2.60%	2.60%	2.57%	2.66%	2.63%
Spire Inc.	$72.53	$73.78	$74.35	$73.54	$76.19	$75.48	$2.25	$2.25	$2.25	$2.25	$2.25	$2.37	3.10%	3.05%	3.03%	3.06%	2.95%	3.14%	3.06%
Enable Midstream Part.	$17.97	$17.27	$16.16	$15.98	$14.36	$13.85	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	7.08%	7.37%	7.87%	7.96%	8.86%	9.19%	8.05%
Enterprise Products	$28.63	$29.09	$28.99	$27.65	$26.69	$25.26	$1.72	$1.72	$1.72	$1.73	$1.73	$1.73	6.01%	5.91%	5.93%	6.26%	6.48%	6.85%	6.24%
Magellan Midstream	$69.32	$70.42	$68.35	$64.75	$61.73	$58.27	$3.75	$3.83	$3.83	$3.83	$3.91	$3.91	5.41%	5.44%	5.60%	5.92%	6.33%	6.71%	5.90%
CSX Corp.	$67.73	$73.17	$73.80	$69.66	$71.10	$66.19	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	1.30%	1.20%	1.19%	1.26%	1.24%	1.33%	1.25%
GATX Corp.	$81.85	$83.91	$84.32	$80.57	$79.91	$76.26	$1.76	$1.76	$1.76	$1.76	$1.76	$1.76	2.15%	2.10%	2.09%	2.18%	2.20%	2.31%	2.17%
Kansas City South'n	$110.89	$116.15	$116.57	$107.33	$100.24	$98.13	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	1.30%	1.24%	1.24%	1.34%	1.44%	1.47%	1.34%
Union Pacific	$144.08	$150.36	$157.67	$150.40	$147.67	$143.86	$2.92	$3.20	$3.20	$3.20	$3.20	$3.20	2.03%	2.13%	2.03%	2.13%	2.17%	2.22%	2.12%
Heartland Express	$19.77	$19.87	$20.51	$18.79	$19.92	$19.01	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	0.40%	0.40%	0.39%	0.43%	0.40%	0.42%	0.41%
Ryder System	$75.02	$77.68	$76.05	$63.97	$54.61	$51.52	$2.08	$2.16	$2.16	$2.16	$2.16	$2.16	2.77%	2.78%	2.84%	3.38%	3.96%	4.19%	3.32%
Amer. States Water	$59.40	$60.08	$59.96	$60.84	$64.26	$66.38	$1.02	$1.10	$1.10	$1.10	$1.10	$1.10	1.72%	1.83%	1.83%	1.81%	1.71%	1.66%	1.76%
Amer. Water Works	$86.59	$88.15	$87.83	$89.78	$91.01	$92.04	$1.82	$1.82	$1.82	$1.82	$1.82	$1.82	2.10%	2.06%	2.07%	2.03%	2.00%	1.98%	2.04%
Middlesex Water	$44.02	$45.25	$47.09	$46.15	$47.97	$54.74	$0.90	$0.90	$0.90	$0.90	$0.96	$0.96	2.03%	1.98%	1.90%	1.94%	2.00%	1.75%	1.93%
York Water Co. (The)	$32.26	$30.03	$30.25	$31.28	$32.19	$32.99	$0.67	$0.67	$0.67	$0.67	$0.67	$0.69	2.07%	2.22%	2.20%	2.13%	2.07%	2.10%	2.13%
MDU Resources	$28.97	$27.64	$26.78	$25.56	$26.05	$24.85	$0.79	$0.79	$0.79	$0.79	$0.79	$0.81	2.73%	2.86%	2.95%	3.09%	3.03%	3.26%	2.99%
EOG Resources	$126.36	$121.30	$121.40	$117.08	$103.51	$95.41	$0.74	$0.74	$0.74	$0.88	$0.88	$0.88	0.59%	0.61%	0.61%	0.75%	0.85%	0.92%	0.72%
National Fuel Gas	$54.30	$54.76	$55.91	$56.59	$52.95	$52.94	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	3.13%	3.10%	3.04%	3.00%	3.21%	3.21%	3.12%

Sources and Notes:
[1] - [6]: Average of Intraday High Low Prices, Monthly
[7] - [12]: Most recent quarterly dividend as of each month from Bloomberg, annualize
[13] - [18]: Dividend yield = Annualized monthly dividends in [7] - [12] divided by corresponding monthly average price (columns [1] - [
[19] = ([13] + [14] + [15] + [16] + [17] + [18]) / 6

Table BV-C5

CINI Sample

LT EPS Growth Rate Forecasts

Company	IBES Growth Estimate	Number of Estimates	ValueLine 3-5 Yr. Growth Rate Estimate	Weighted Average Short-Term Growth
	[1]	[2]	[3]	[4]
Delta Air Lines	16.8%	5	12.3%	16.1%
Southwest Airlines	15.9%	4	9.1%	14.5%
FedEx Corp.	9.7%	5	3.4%	8.7%
United Parcel Serv.	11.6%	7	6.6%	11.0%
Atmos Energy	6.5%	2	4.9%	5.9%
Chesapeake Utilities	n/a		9.8%	9.8%
NiSource Inc.	5.9%	3	8.5%	6.6%
Northwest Natural	4.0%	1	12.3%	8.2%
ONE Gas Inc.	5.5%	2	9.3%	6.8%
Southwest Gas	6.2%	2	8.1%	6.8%
Spire Inc.	2.7%	2	5.7%	3.7%
Enable Midstream Part.	8.1%	2	22.5%	12.9%
Enterprise Products	9.4%	3	8.6%	9.2%
Magellan Midstream	8.0%	2	0.7%	5.6%
CSX Corp.	23.2%	5	10.4%	21.1%
GATX Corp.	12.0%	1	6.0%	9.0%
Kansas City South'n	14.7%	2	11.5%	13.6%
Union Pacific	18.3%	5	10.4%	17.0%
Heartland Express	27.1%	1	15.3%	21.2%
Ryder System	14.6%	1	11.9%	13.2%
Amer. States Water	6.0%	1	10.9%	8.5%
Amer. Water Works	8.2%	1	8.1%	8.1%
Middlesex Water	n/a		5.9%	5.9%
York Water Co. (The)	n/a		9.8%	9.8%
MDU Resources	n/a		15.2%	15.2%
EOG Resources	102.6%	2	16.1%	73.7%
National Fuel Gas	n/a		7.3%	7.3%

Sources and Notes:
[1] & [2]: Thomson Reuters as of December 31, 2018.
[3]: ValueLine Investment Analyzer as of 12/31/2018. Calculated as compoung annual growth rate (CAGR) using current year EPS estimate and Projected 3-5 year EPS estimate.
[4] = ([1] × [2] + [3]) / ([2] + 1)

Table No. BV-C8

CINI Sample

CAPM ROE Estimates

Company	RFR	Risk Premium	Beta	Unadjusted Ke	Market Cap ($Million)	Size Adjustment	Implied Cost of Equity
	[1]	[2]	[3]	[4] = [1] + [2]x [3]	[5]	[6]	[7] = [4] + [6]
Delta Air Lines	3.70%	9.67%	1.20	15.3%	$34,624	-0.35%	15.0%
Southwest Airlines	3.70%	9.67%	1.15	14.8%	$26,316	-0.35%	14.5%
Atmos Energy	3.70%	9.67%	0.60	9.5%	$10,141	0.89%	10.4%
Chesapeake Utilities	3.70%	9.67%	0.65	10.0%	$1,306	1.72%	11.7%
NiSource Inc.	3.70%	9.67%	0.50	8.5%	$9,199	0.89%	9.4%
Northwest Natural	3.70%	9.67%	0.60	9.5%	$1,738	1.66%	11.2%
ONE Gas Inc.	3.70%	9.67%	0.65	10.0%	$4,111	0.98%	11.0%
Southwest Gas	3.70%	9.67%	0.70	10.5%	$3,729	0.98%	11.4%
Spire Inc.	3.70%	9.67%	0.65	10.0%	$3,711	0.98%	11.0%
Enable Midstream Part.	3.70%	9.67%	1.25	15.8%	$5,706	0.89%	16.7%
Enterprise Products	3.70%	9.67%	1.30	16.3%	$52,908	-0.35%	15.9%
Magellan Midstream	3.70%	9.67%	1.20	15.3%	$12,850	0.61%	15.9%
CSX Corp.	3.70%	9.67%	1.20	15.3%	$52,405	-0.35%	15.0%
GATX Corp.	3.70%	9.67%	1.30	16.3%	$2,718	1.51%	17.8%
Kansas City South'n	3.70%	9.67%	1.10	14.3%	$9,753	0.89%	15.2%
Union Pacific	3.70%	9.67%	1.10	14.3%	$101,143	-0.35%	14.0%
Heartland Express	3.70%	9.67%	0.90	12.4%	$1,484	1.72%	14.1%
Ryder System	3.70%	9.67%	1.30	16.3%	$2,551	1.51%	17.8%
Amer. States Water	3.70%	9.67%	0.70	10.5%	$2,444	1.51%	12.0%
Amer. Water Works	3.70%	9.67%	0.55	9.0%	$16,147	0.61%	9.6%
Middlesex Water	3.70%	9.67%	0.75	11.0%	$851	2.08%	13.0%
York Water Co. (The)	3.70%	9.67%	0.75	11.0%	$407	2.68%	13.6%
EOG Resources	3.70%	9.67%	1.45	17.7%	$51,483	-0.35%	17.4%
MDU Resources	3.70%	9.67%	1.00	13.4%	$4,567	0.98%	14.3%
National Fuel Gas	3.70%	9.67%	1.00	13.4%	$4,460	0.98%	14.3%
FedEx Corp.	3.70%	9.67%	1.15	14.8%	$42,033	-0.35%	14.5%
United Parcel Serv.	3.70%	9.67%	0.90	12.4%	$83,993	-0.35%	12.1%
						Min	9.4%
						Max	17.8%
						Median	14.1%
						Midpoint	13.6%
						Max (Outlier Tested)	17.8%

Sources and Notes:
[1], [2]: See BV Table No. BV-8 Electric Utility Sample.
[3], [5]: Value Line Investment Analyzer as of 12/31/2018.
[6]: Duff&Phelps 2017 Valuation Handbook U.S. Guide to Cost of Capital, 7-10 and 7-11.

Table No. BV-C10: Expected Earnings Method ROE for FERC Capital Intensive Sample

Company	Ticker	2021-23 Expected Return on Common Equity	Adjustment Factor	Adjusted Return on Common Equity (full sample)
[1]	[2]	[4]	[5]	[6]
Delta Air Lines	DAL	25.5%	1.04	26.4%
Southwest Airlines	LUV	23.0%	1.02	23.4%
FedEx Corp.	FDX	18.0%	1.03	18.6%
United Parcel Serv.	UPS	NA	1.10	NA
Atmos Energy	ATO	11.0%	1.02	11.3%
Chesapeake Utilities	CPK	10.0%	1.05	10.5%
NiSource Inc.	NI	11.5%	1.01	11.6%
Northwest Natural	NWN	12.0%	1.02	12.2%
ONE Gas Inc.	OGS	11.0%	1.02	11.2%
Southwest Gas	SWX	9.5%	1.04	9.9%
Spire Inc.	SR	10.0%	1.02	10.2%
Enable Midstream Part.	ENBL	11.5%	1.02	11.7%
Enterprise Products	EPD	24.0%	1.00	24.1%
Magellan Midstream	MMP	46.0%	1.01	46.5%
CSX Corp.	CSX	30.5%	1.00	30.6%
GATX Corp.	GATX	11.0%	1.01	11.1%
Kansas City South'n	KSU	16.5%	1.01	16.7%
Union Pacific	UNP	43.0%	0.99	42.4%
Heartland Express	HTLD	14.0%	1.04	14.5%
Ryder System	R	11.5%	1.03	11.8%
Amer. States Water	AWR	14.0%	1.01	14.1%
Amer. Water Works	AWK	10.5%	1.03	10.8%
Middlesex Water	MSEX	13.0%	1.02	13.2%
York Water Co. (The)	YORW	13.5%	1.02	13.7%
MDU Resources	MDU	14.0%	1.03	14.5%
EOG Resources	EOG	17.0%	1.07	18.2%
National Fuel Gas	NFG	16.5%	1.06	17.5%

	Full Sample
Median	13.9%
Minimum	9.9%
Maximum	46.5%
Median (Outlier Tested)	12.0%
Maximum (Outlier Tested)	18.02%

Sources and Notes:
[4]: Value Line Investment Survey Reports published in October/November 2018. If Return on Common Equity not available, then used Return on Shareholder or Partner Equity.
[6] = [4] x [5]
[7]: [6] if included in subsample, see [3].

WP-BV-C10: Adjustment Factor Calculation for FERC Capital Intensive Sample

Company	2018			2021-2023			Change in Equity	Adjustment Factor
	Equity Share	Total Capital	Total Equity (Millions)	Equity Share	Total Capital	Total Equity (Millions)		
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Delta Air Lines	N/A	N/A	$14,820	N/A	N/A	$21,460	7.7%	1.0370
Southwest Airlines	N/A	N/A	$10,635	N/A	N/A	$12,400	3.1%	1.0154
FedEx Corp.	N/A	N/A	$19,416	N/A	N/A	$26,450	6.4%	1.0309
United Parcel Serv.	N/A	N/A	$3,470	N/A	N/A	$9,625	22.6%	1.1017
Atmos Energy	65.5%	$7,265	$4,759	55.0%	$11,000	$6,050	4.9%	1.0240
Chesapeake Utilities	68.0%	$795	$541	70.0%	$1,300	$910	11.0%	1.0520
NiSource Inc.	41.0%	$12,675	$5,197	39.0%	$15,005	$5,852	2.4%	1.0119
Northwest Natural	52.5%	$1,485	$780	53.5%	$1,750	$936	3.7%	1.0183
ONE Gas Inc.	68.0%	$3,000	$2,040	62.0%	$3,850	$2,387	3.2%	1.0157
Southwest Gas	48.0%	$4,150	$1,992	52.5%	$5,700	$2,993	8.5%	1.0407
Spire Inc.	54.3%	$4,156	$2,256	55.0%	$5,115	$2,813	4.5%	1.0221
Enable Midstream Part.	N/A	N/A	$7,470	N/A	N/A	$9,000	3.8%	1.0186
Enterprise Products	N/A	N/A	$23,400	N/A	N/A	$24,000	0.5%	1.0025
Magellan Midstream	N/A	N/A	$2,700	N/A	N/A	$3,000	2.1%	1.0105
CSX Corp.	N/A	N/A	$12,700	N/A	N/A	$13,250	0.9%	1.0042
GATX Corp.	N/A	N/A	$1,840	N/A	N/A	$1,975	1.4%	1.0071
Kansas City South'n	N/A	N/A	$4,650	N/A	N/A	$5,200	2.3%	1.0112
Union Pacific	N/A	N/A	$20,300	N/A	N/A	$17,500	-2.9%	0.9852
Heartland Express	N/A	N/A	$590	N/A	N/A	$850	7.6%	1.0365
Ryder System	N/A	N/A	$3,000	N/A	N/A	$3,900	5.4%	1.0262
Amer. States Water	58.5%	$1,010	$591	54.0%	$1,200	$648	1.9%	1.0092
Amer. Water Works	43.5%	$13,085	$5,692	42.5%	$18,625	$7,916	6.8%	1.0330
Middlesex Water	62.5%	$390	$244	62.5%	$460	$288	3.4%	1.0165
York Water Co. (The)	62.0%	$210	$130	66.0%	$230	$152	3.1%	1.0153
MDU Resources	N/A	N/A	$2,520	N/A	N/A	$3,570	7.2%	1.0348
EOG Resources	N/A	N/A	$19,250	N/A	N/A	$38,000	14.6%	1.0679
National Fuel Gas	N/A	N/A	$1,937	N/A	N/A	$3,500	12.6%	1.0591

Sources and Notes:
[1],[2],[4],[5]: Value Line Investment Survey Business Reports published in October and November 2018.
[3]: [1] x [2] if common equity data available, otherwise shareholder or partner equity from Value Line Business Reports published in October and November 2018.
[6]: [4] x [5] if common equity data available, otherwise shareholder or partner equity from Value Line Business Reports published in October and November 2018.
[7]=([6]/[3])^(1/5) -1
[8]=2*(1+[7])/(2+[7])